Louisiana Public Service Commission

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January 8, 2019

VIA HAND DELIVERY
Ms. Terri Bordelon
Louisiana Public Service Commission
Records and Recordings
602 N. Fifth St.
Galvez Bldg, 12th Fl.
Baton Rouge, LA 70802

Re: Docket No. R-33929, Louisiana Public Service Commission, ex parte.

Dear Ms. Bordelon:

Enclosed for filing is a *Notice of Staff Recommendation on Final Proposed Rule* in the above-referenced dockets.

Please do not hesitate to contact me if you have any questions concerning this filing.

Very Truly Yours,

KHB

Kathryn H. Bowman
Staff Attorney

KHB/kst
Encl.
cc: Service List

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

2019 JAN -8 AM 10:22

LA PUBLIC SERVICE COMMISSION

DOCKET NO. R-33929

LOUISIANA PUBLIC SERVICE COMMISSION, EX PARTE

In Re: Review of Policies Related to Customer-owned Solar Generation and Possible Modification of the Commission's Current Net Metering Rules.

NOTICE OF STAFF RECOMMENDATION ON FINAL PROPOSED RULE

PLEASE TAKE NOTICE that attached hereto is *Staff's Review of Louisiana Public Service Commission's Rules Regarding Distributed Generation: Report on Phase II of Rule-Making* and Staff's final proposed Distributed Generation Rules. This report and final proposed Distributed Generation Rule takes into consideration the two sets of comments received from the intervenors in this proceeding. The attached final proposed rule will be considered at an upcoming Commission Business and Executive Session.[1]

/s/ Noel J. Darce
Paul L. Zimmering (#13798)
Noel J. Darce (#01813)
Of
STONE PIGMAN WALTHER WITTMANN L.L.C.
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[1] This matter will not be considered at the January 16, 2019 Business and Executive Session.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the above and foregoing has been served upon all parties of record in Docket Nos. R-33929 by email properly addressed on this 8th day of January, 2019.

KATHRYN H. BOWMAN

LOUISIANA PUBLIC SERVICE COMMISSION

DOCKET NO. R-33929

LOUISIANA PUBLIC SERVICE COMMISSION, EX PARTE

In Re: ***Review of Policies Related to Customer-owned Solar Generation and Possible Modification of the Commission's Current Net Metering Rules.***

Review of LPSC Rules Regarding Distributed Generation: Report on Phase II of Rule-Making

Prepared on behalf of
Louisiana Public Service Commission

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Final Report
January 8, 2019

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Executive Summary

At its December 2015 Business and Executive Session ("B&E"), the Louisiana Public Service Commission ("LPSC" or "the Commission") approved a proposal for Acadian Consulting to assist the in-house Commission Staff with a two-phase rulemaking designed to: 1) modify the Commission's then current net metering Rule in order to address how new solar customers should be compensated once a utility reaches the net metering cap found in § 5.02 of the Rule (on an expedited basis); and 2) examine appropriate changes to solar policies in Louisiana on a longer term comprehensive basis.

The Commission's rulemaking docket was published in the Commission's Official Bulletin dated December 29, 2015. Along with the official bulletin publication, Staff proposed Phase I modifications to the Commission's net metering Rule designed to address issues related to post-cap remuneration, specifically recognizing the need and opportunity for further changes to the Commission's net metering Rule in Phase II. Upon consideration of party comments to proposed Phase I rulemaking changes, Staff filed its recommendation into the record on April 15, 2016. The Commission ultimately accepted Staff's proposed recommendation at its November 17, 2016 B&E, memorializing the Commission's decision in the General Order dated December 8, 2016 ("Phase I").

At its December 21, 2016 B&E, the Commission directed the Staff to move forward with Phase II of the rulemaking. At its January 18, 2017 B&E, the Commission issued directions regarding the completion of a consultant's report and directed Staff to file a request for comments from interested parties. Staff filed its initial request for comments on January 20, 2017. In its request, Staff sought written comments to assist it in its determination of whether a more effective approach to supporting existing and facilitating new behind-the-meter or distributed generation could be developed. Staff specifically requested party comments on the following five questions:

1) Should the Commission maintain the current net energy metering ("NEM") Rule or is there an alternative to NEM that could fairly and justly compensate owners of DERs while minimizing cross-subsidization? Please explain.

2) If you believe the Commission should maintain the current NEM Rule, please comment on any changes that should be made and why.

3) If you believe the Rule should be changed to incorporate 2-channel billing how should the net excess generation be valued and how can the Commission ensure that the compensation is:

   a. Administratively traceable and not burdensome;

   b. Appropriately updated given changes in time, location and resource attributed;

   c. Transparent and non-discriminatory;

   d. Based upon known and measurable information consistent with the Commission's traditional ratemaking/fuel procurement policies.

4) Are there other retail service offerings the Commission could require utilities to implement that would alleviate some of the concerns with DER valuation such as a time of use tariff? Please explain.

5) The current NEM Rule define a net metering facility as one that is, in part, intended primarily to offset part or all of the net-metering customer requirements for electricity. i.e., a facility should not be sized to produce net excess generation on a monthly basis. How can the Commission ensure that net metering facilities are not over-sized?

Over the course of its investigation, Staff requested two separate sets of comments from parties. Through these requests for comments, Staff received comments from ten parties: Alliance for Affordable Energy ("AAE"), Association of Louisiana Electric Cooperatives ("ALEC"), Cleco Power LLC ("Cleco"), Entergy Louisiana, LLC ("Entergy" or "ELL"), Gulf States Renewable Energy Industries Association ("GSREIA"), PosiGen of Louisiana, LLC ("PosiGen"), the Sierra Club, Southwestern Electric Power Company ("SWEPCO"), Walmart Louisiana LLC and Sam's East, Inc. (collectively "Walmart"), and Wilhite Energy, LLC ("Wilhite").

The remainder of this report is divided into three sections. Section I provides a history of distributed energy resource policy and trends in net metering and related policies both on a national and Louisiana level. Section II provides a summary and response to party comments in this proceeding. Section III provides a summary discussion of the proposed Commission rule change. Also attached hereto to as Exhibit A is a copy of the proposed Phase II Commission Rule.

Section I

History of Distributed Energy Resource Policy and Louisiana and National Trends in Net Metering and Related Policies

Section I. History of Distributed Energy Resource Policy and Louisiana and National Trends in Net Metering and Related Policies

1.1. Definition and Overview

Net Energy Metering ("NEM") projects are almost exclusively associated with what are called "behind-the-meter" generation applications, or more commonly referred to as "distributed energy resources" ("DER"). DER applications are typically small-scale generation or storage devices located on the customer side of the meter designed primarily to serve customer (or "host") energy needs. The size of what constitutes a DER application can often vary, is subjective, and is often constrained by regulatory decisions and/or state statutes. While DER sizes can vary, they are almost exclusively interconnected to the utility grid at either the primary or secondary distribution level.[1]

DER applications span a wide range of technologies that include solar, small-scale wind, and in some rare instances, biomass/biogas generation. DER is not limited to just renewable energy technologies and can include a number of prime movers that combust/utilize fossil fuels such as reciprocating engines, micro-turbines, and fuel cells. Fixed location stand-by generators, common at many South Louisiana commercial establishments and homes, are used to generate electricity during tropical storm activity-created outages, and are examples of fossil-fuel based DER applications.

NEM applications are a subset of DER: not all DER applications are net metered, but all NEM applications represent various forms of DER. NEM generators are DER applications that are given special regulatory dispensations typically not afforded to other small-scale distribution-level generators. Energy use and generation at a NEM installation is generally measured in a fashion that "credits" an on-site generation customer when excess power is "put" to the distribution grid and then "charges" that same customer at times when usage is greater than

[1] Electric energy leaves the distribution substation and is distributed to different areas by distribution lines. Distribution lines on the high voltage side of the distribution transformer are called primary distribution lines and those on the low-voltage side of the distribution transformer are called secondary distribution lines.

the on-site generator's capacity. Hence, the prefix "net": these energy charges and credits are reconciled to calculate a "net" usage for the on-site generation customer. The special regulatory dispensation offered to these NEM generators includes providing a relatively streamlined and consistent process for distribution level interconnection, and a regulatory-established set of rates or credits that are offered as reimbursement for NEM-generated electricity put to a regulated electric utility's distribution grid.

The regulatory conditions for NEM eligibility vary across the U.S., although there are usually three basic requirements. The first eligibility requirement is usually based upon technology type. Most NEM policies across the U.S. require the NEM installation to be based upon a renewable technology; however, there are some exceptions to this eligibility requirement. For instance, Maine, Maryland, and Massachusetts all allow combined heat and power ("CHP") of up to a specified size and/or efficiency rating to qualify as a NEM facility. However, for all intents and purposes, most NEM programs across the U.S. are heavily dominated by rooftop solar technologies.

The second eligibility requirement is usually based upon customer class. NEM eligibility is usually restricted to residential customers, and in some instances, commercial customers. Both customer classes (residential and small commercial) are usually interconnected to the utility grid at the secondary distribution level, and are also perceived to be the customers facing the highest institutional and economic hurdles related to on-site generation installations.

The third eligibility requirement is based upon the size of the particular NEM installation. Many state NEM policies restrict residential installations to those under 25 kW although there are some states that have no direct size limitations on these residential installations provided they are not larger than on-site usage. Most states require NEM installations to be sized proximate to the loads being served by the on-site generators. For those states allowing small commercial customer participation, installation size restrictions are usually around 2 MW, but again, some states, like New Jersey, have no restrictions on small commercial installation sizes provided they are proximate to the customer's on-site usage.

Each of these restrictions have been adopted to limit NEM program scope, and to prevent NEM projects from becoming so large that they have unintended negative impacts on non-NEM participating customers (i.e., other utility ratepayers). An additional rationale for NEM policy restrictions is to reduce the opportunities for regulatory "gaming," preventing DER installations from becoming "mini-merchant power plants" that sell a considerable (relative) amount of power back to the distribution grid.

Historically, the purpose of NEM policies has been to remove barriers associated with the development of small-scale DER, particularly for residential and small commercial customers where these barriers are often perceived as being more challenging. Three common barriers to DER development that are typically eliminated by NEM policies include those associated with generator interconnection, the ability to access standby and emergency electrical service, and access to some type of market to deliver/sell excess electricity periodically generated when loads are lower than on-site generator capabilities arises. These barriers are not too dissimilar to those faced by large scale cogeneration applications, and removed by the Public Utilities Regulatory Policies Act of 1978 ("PURPA").[2]

NEM policies have arisen over the past several decades to maximize the perceived benefits associated with DER. For instance, DER can provide electricity customers with greater reliability, higher power quality, and more flexible electric service choices, particularly on a qualitative basis. Many DER technologies, particularly renewables, can be more environmentally friendly than generation produced from typical utility service and, if structured properly, can reduce end-user price volatility that can arise with fossil-fuel based generation. Widespread use of DER technologies could also mitigate future utility capacity requirements that include avoiding future generation, transmission and distribution-related investments.

1.1.1. Recent NEM Installation and Capacity Development Trends

The Energy Information Administration ("EIA") collects NEM data as part of the "Monthly Electric Sales and Revenue with State Distributions Report" that is filed by electric utilities and suppliers also known as the

[2] In 1978, Congress passed the "National Energy Act" (NEA) which was composed of five different statutes, one of which was PURPA. The goal of PURPA was to eliminate barriers to industrial "CHP" applications in order to increase energy efficiency and improve electric system reliability.

Form EIA 826. The purpose of this form is to collect information from electric utilities, energy service providers, and distribution companies that sell or deliver electric power to end users. The survey was expanded in 2011 to include data on NEM installations, NEM installation types, NEM capacities, and NEM net generation.[3] While national and state level comparisons can be conducted with this data, these comparisons are unfortunately limited to the last six years.

Figure 1 shows the trend in U.S. and Louisiana NEM capacity over the past several years. The most recently-available data reports total U.S. NEM customers at 1,769,432 accounting for 18,104 MW of NEM capacity: over 94 percent of this national NEM capacity is associated with solar behind-the-meter installations. Over the past five years, U.S. NEM capacity has grown at an average annual rate of 36 percent compared to Louisiana NEM capacity which grew at an average annual rate of about 44 percent over the same time period. Louisiana currently ranks 19th among states in total NEM installed capacity.

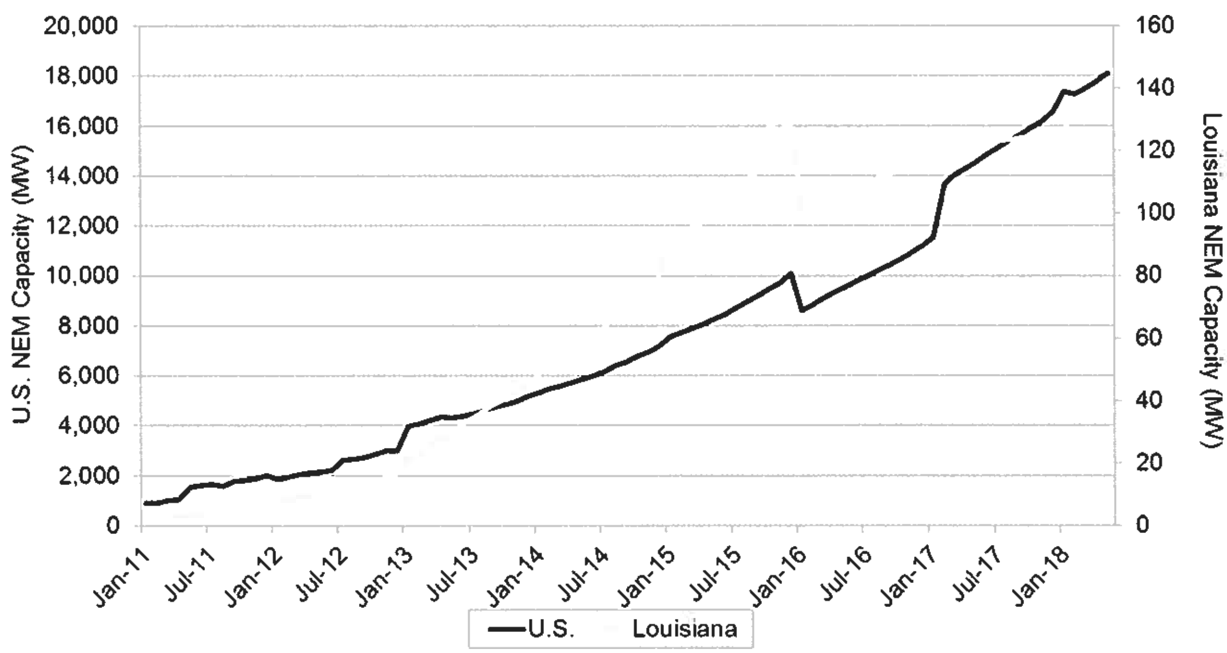

Figure 1: U.S. and Louisiana Installed NEM Capacity (MW)
Source: Energy Information Administration, Form 826.
Note: Figure above includes both LPSC-jurisdictional and non-LPSC-jurisdictional utilities.

[3] Net generation is defined as gross NEM system generation less on-site electricity consumption.

Figure 2 compares state-level NEM capacity growth over the past five years. Louisiana's NEM capacity growth, on a percentage basis, is one of the fastest in the entire U.S. outpacing traditional renewable energy promoting states such as California and Oregon.

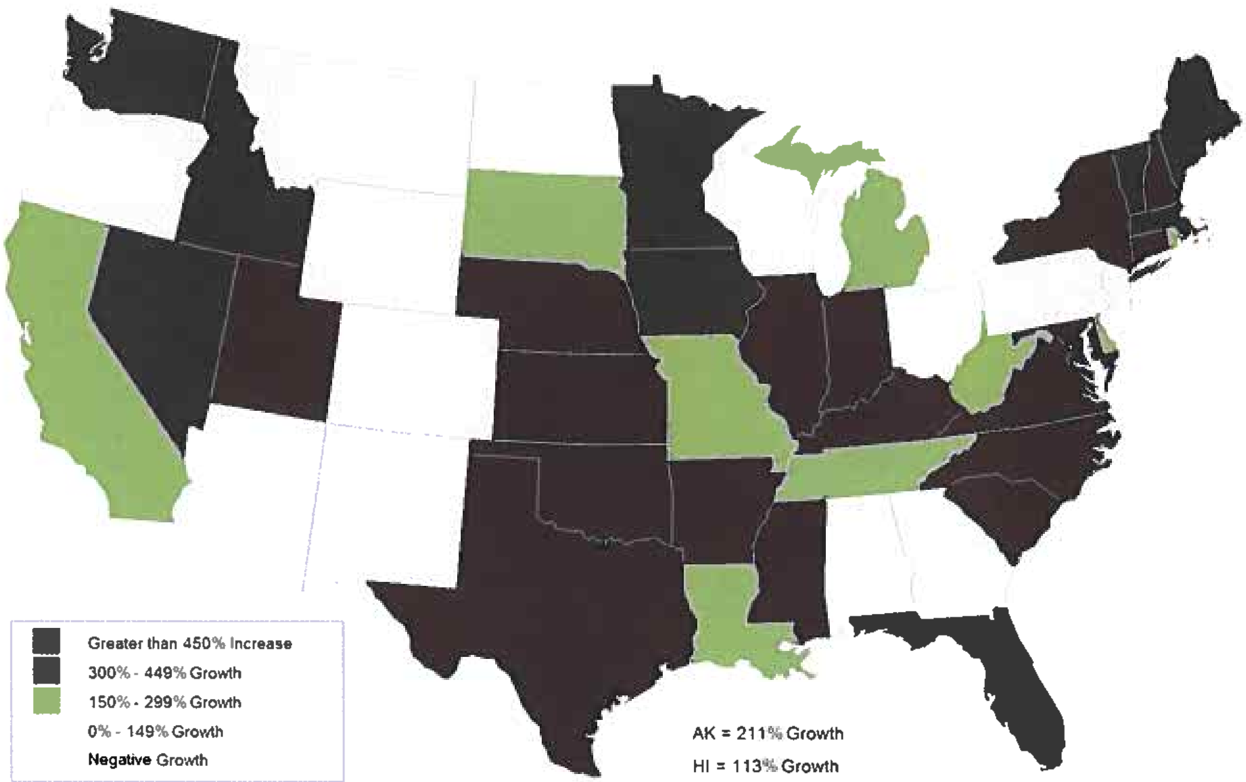

Figure 2: Net Metered Capacity Growth (January 2013 through March 2018)
Source: Energy Information Administration, Form EIA-826.

The dramatic growth in NEM installations, particularly solar NEM installations, can largely be attributed to three factors. The first is regulatory policy encouraging NEM development; the second is federal and state tax policy encouraging NEM development; and the last is reduction of solar panel and installation costs.

1.2. Regulatory Policies Supporting NEM Installation Growth

1.2.1. History of State NEM Adoption

The origins of state NEM polices date back to the early days of PURPA implementation in the early 1980s which attempted to extend the access, buy-back and back-up provisions afforded to large scale co-generators to smaller, distribution level generation resources. In the early 1980s, ten states had enacted either NEM policies, programs, or legislation.

The Congressional passage of the Energy Policy Act of 1992 ("EPAct 1992") brought a renewed interest in efficiency and small-scale generation opportunities. Several states during the 1990s, as part of reviewing and implementing policies outlined in EPAct 1992, adopted utility-specific or statewide NEM policies. These policies represent the more "modern" period of NEM adoption and are the basis for many state NEM policies that are still in place. The increased "sophistication" and understanding of DER resulted in new and additional restrictions on state regulatory NEM policies to ensure that only those generators bringing renewable or efficiency benefits, as opposed to those that simply offered simple cycle generation opportunities, were being promoted. All but two net metering regulations implemented during the 1990s limited NEM eligibility to only renewable technologies. During the 1990's eleven more states enacted state polices for NEM.[4]

Currently, 48 states and the District of Colombia have one or more utilities within the state offering net metering service, and many state policies currently allow NEM state-wide. One of the important factors motivating this large-scale adoption of NEM regulatory policies has been the more recent adoption (at least over the past decade) of renewable energy portfolio standards ("RPS"). Figure 3 shows 38 states and the District of Columbia have adopted an RPS or renewable energy goal.[5]

[4] Wan, Yih-huei and H. James Green. 1998. Current Experience with Net Metering Programs, National Renewable Energy Laboratory, Presented at Wind Power '98 (Bakersfield, CA), pp. 7-9.

[5] National Conference of State Legislatures; State Renewable Portfolio Standards and Goals (July 20, 2018) Internet website: http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

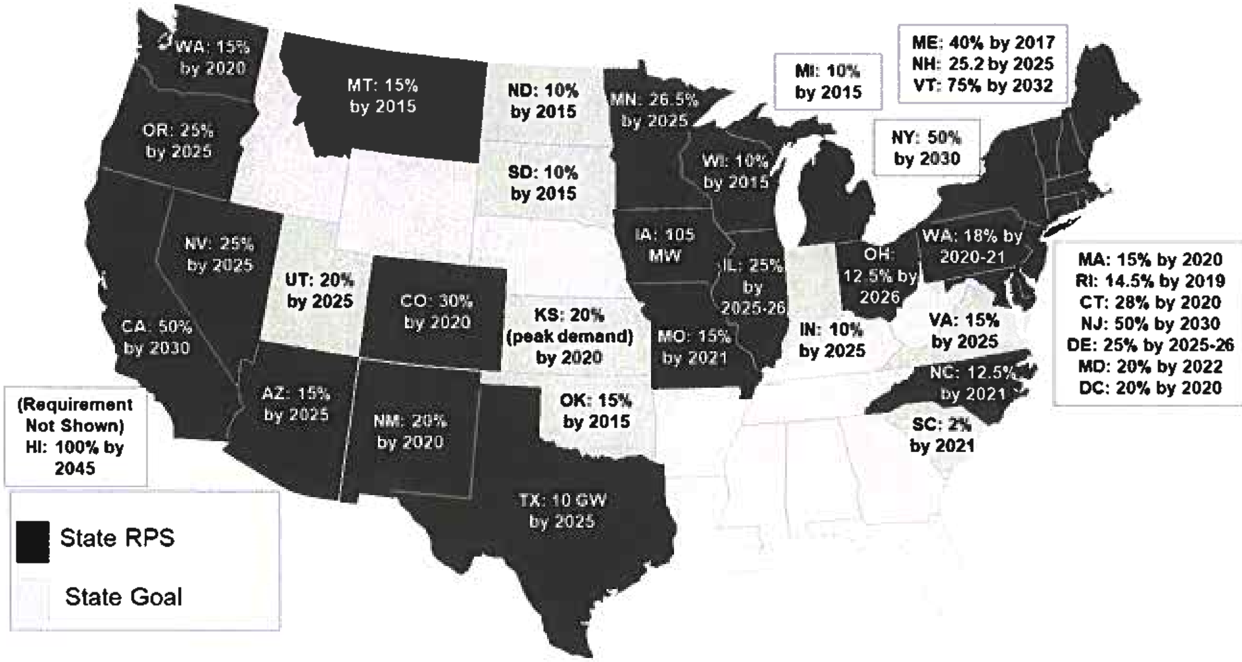

Figure 3: State Renewable Portfolio Standards as of July 2018
Source: National Conference of State Legislatures ("NCSL")

RPS states, collectively, represent over 75 percent of current retail U.S. electricity sales and the anticipated growth of renewable generation shares are anticipated to increase by as much as one-third of some states' retail electricity sales by 2030. This rapid escalation of renewable generation, a large portion of which will likely come from behind-the-meter renewable generation applications, is largely the reason why many states have been compelled to revisit, and in some instances modify, their earlier NEM policies. NEM-facilitated DER has moved from being niche installations, as envisioned in the 1980s and 1990s, to a resource base that could comprise a significant share of future U.S. electric generating resources.

1.2.2. Growth of Alternative Net Metering Structures

In recent years, there has been a growing movement away from traditional net metering that directly credit electricity exported to the electric grid from distributed generation units against electricity used by the net metered customers. Instead, a growing number of states have been valuing 'out-flows' from the net metered generator at rates that are independent to retail electricity rates charged to the customer for electric use.

Three alternatives to net metering have emerged, the first of which is what has been referred to as "2-Channel Billing," wherein all electricity exported by the distributed generation facility is valued at a rate consistent with the associated utility's avoided cost of electricity. Nevada was the first state to adopt such a

structure in February 2016 after the Public Utilities Commission of Nevada ("PUCN") rejected a proposal by Nevada Power Company and Sierra Pacific Power Company ("NV Energy") for approval of a cost-of-service study and NEM tariffs.[6] However, the PUCN decision was followed shortly thereafter by similar policy changes in Arizona,[7] Hawaii,[8] and Indiana.[9] More recently, Michigan has adopted a net metering approach that could be considered 2-Channel Billing in nature.[10] Notably, in June 2017, the Nevada Legislature passed a statute that effectively overturned the PUCN's February 2016 decision and reinstated traditional net metering in the state.[11]

The second alternative to traditional net metering that has emerged in recent years is an alternative that has been referred to as "Value of Solar" ("VOS"), which was developed concurrently with the 2-Channel Billing approach and bears many similarities. Like 2-Channel Billing, VOS prices electricity delivered by a distributed generation facility separately from retail rates, but this price is determined by an analysis of the avoided energy, capacity, and potentially environmental benefits of solar generation. This results in a rate that is typically below retail rates, but greater than wholesale avoided energy rates. Mississippi, for example, prices electricity exported by a distributed generation facility at 2.5 cents plus the applicable utility's avoided cost rate.[12]

The third alternative to traditional net metering limits the portion of exported electricity from a distributed generation facility that can be applied against a customer's transmission and distribution portions of electric bills. In March 2017, the Maine Public Utilities Commission completed a rulemaking process to replace its traditional net metering rules with a revised version that would phase-out the ability of net metered customers to use distributed generation systems to net charges associated with transmission and distribution service over a 15 year

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[6] *Application of Nevada Power Company d/b/a NV Energy for approval of a cost-of service study and net metering tariffs,* Docket No. 15-07041 and *Application of Sierra Pacific Company d/b/a NV Energy for approval of a cost-of-service study and net metering tariffs,* Docket No. 15-07042, Modified Final Order, ¶ 94 (February 12, 2016).

[7] *In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation,* Arizona Corporation Commission Docket No. E-00000J-14-0023, Decision No. 7859 (January 3, 2017).

[8] *Instituting a Proceeding to Investigate Distributed Energy Resource Policies,* Docket No. 2014-0192, Order No. 33258, pp. 126-127 (October 12, 2015).

[9] Indiana Senate Bill 309, Chapter 40, §§ 10 and 17.

[10] *In the matter, on the Commission's own motion, to implement the provisions of Sections 173 and 183(1) of 2016 PA 342, and Section 6a(14) of 2016 PA 341,* Case No. U-18383, Order (April 18, 2018).

[11] *Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of Tariff Schedules and Rates Pursuant to Assembly Bill 405,* Docket No. 17-07026, Order Granting in Part and Denying in Part Joint Application by NV Energy on Assembly Bill 405, pp. 14-17 (September 1, 2017).

[12] In re: Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards, Mississippi Public Service Commission Docket No. 2011-AD-2, Order Adopting Net Metering Rule (December 3, 2015).

period.[13] Shortly after Maine adopted this revised net metering approach, New Hampshire approved a similar policy change that reduced the creditable portion of distributed generation to only 25 percent for distribution purposes.[14]

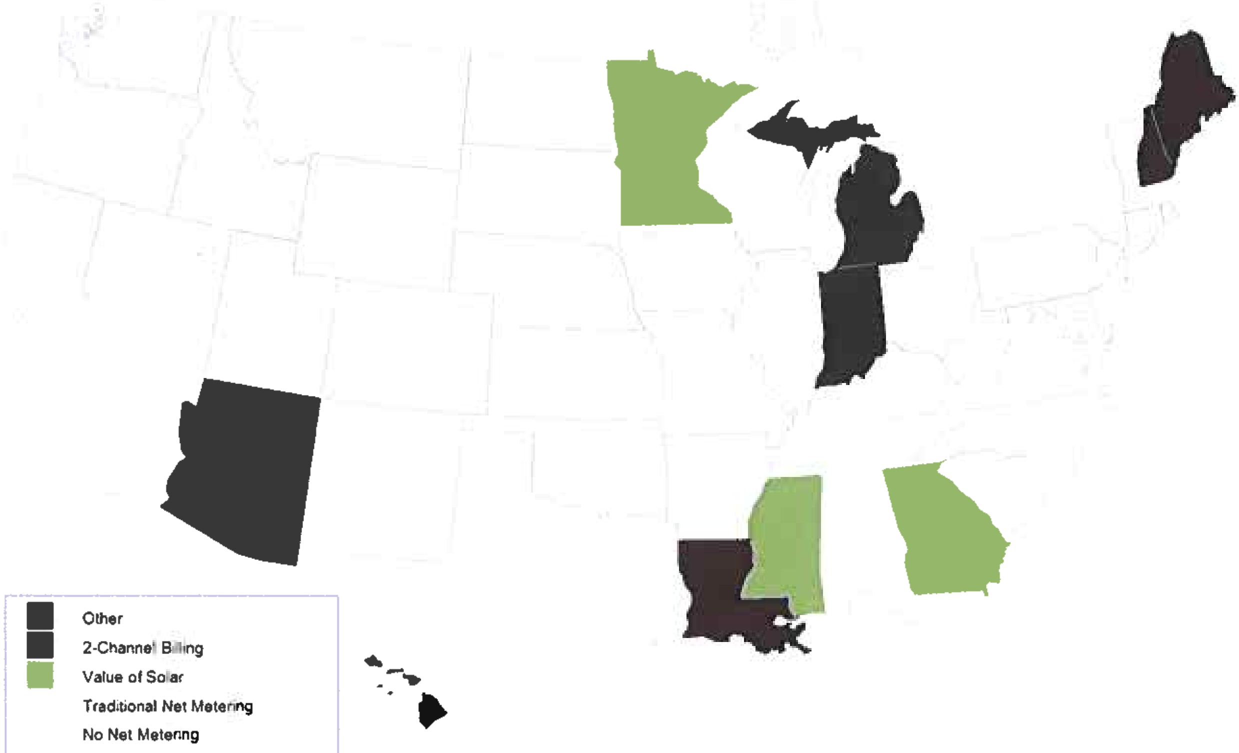

Figure 4: Alternative Net Metering Policies
Source: State Statutes and Regulations

1.2.3. Individual System Size Requirements

Most states limit the size of NEM resources. These size limitations, however, vary by state. There are currently five states (Arizona, Colorado, Georgia, Ohio, and New Jersey) that do not implement a strict size limitation, but evaluate systems on an application by application basis based on a percentage of total annual usage. Each state's NEM installation-specific size limitations is presented in Figure 5.

[13] *Public Utilities Commission Amendments to Net Energy Billing Rule (Chapter 313)*, Public Utilities Commission of Maine Docket No. 2016-00222, Order Adopting Rule and Statement of Factual and Policy Basis (March 1, 2017).
[14] *Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms and Tariffs for Customer-Generators*, Docket No. DE 16-576, Order Accepting Settlement Provisions, Resolving Settlement Issues, and Adopting a New Alternative Net Metering Tariff ("Order No. 26,029"), p. 100 (June 23, 2017).

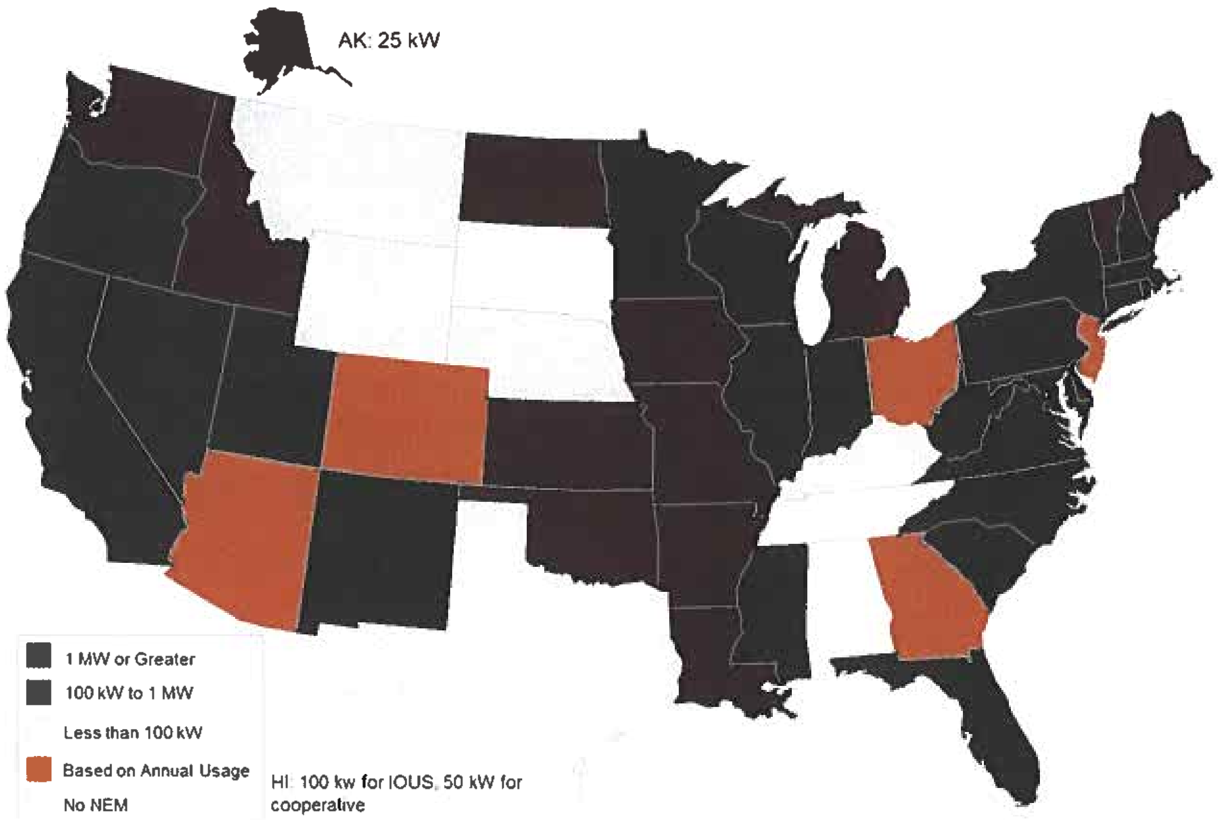

Figure 5: State Policies Regarding System Capacity Limits
Source: State Statutes and Regulations

Many states also have system limitations for residential systems separate from larger commercial and industrial systems. In 2014 there were only 14 states that had separate residential system limitations. However, this amount has changed significantly since that time with nearly every state with NEM policies setting separate size limitations for residential systems. Figure 6 shows that currently only five states do not set system limitations for residential systems.

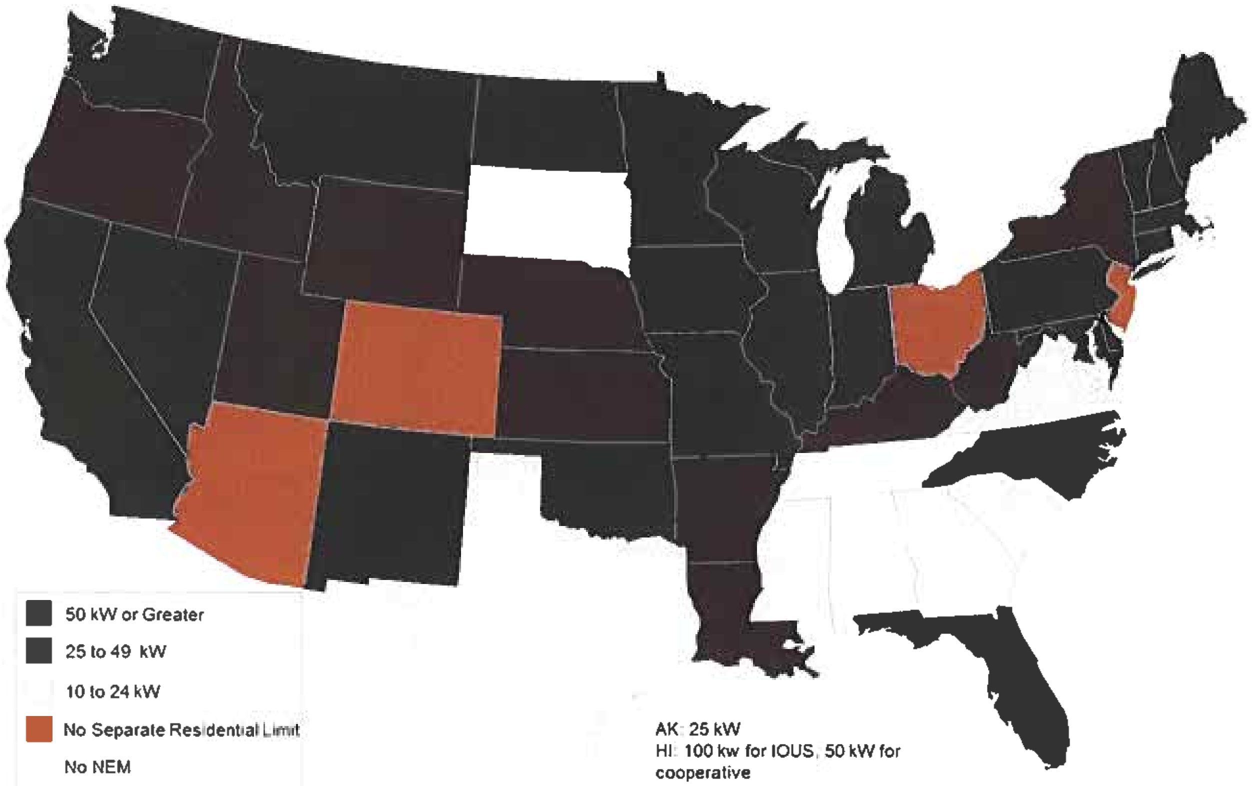

Figure 6: State Policies Regarding Residential System Capacity Limits
Source: State Statutes and Regulations

1.2.4. Aggregate Installation Limits

Most states have aggregate capacity limitations on the total NEM capacity that can be installed on a utility system during any given time. Figure 7 shows that 28 states (56 percent) have aggregate NEM installation limits. Nine states have aggregated capacity limits of between 1 percent and 2.9 percent of a utility system's annual peak demand, while another three states, have set aggregated capacity limits on net metering at less than 1 percent of a utility system's annual peak demand. Another three states (Maryland, Nevada, and New Hampshire) impose an aggregate NEM capacity cap that is not tied to a utility's annual system peak. For instance, Maryland has administratively limited capacity from net metering to 1,500 MW[15] which applies on a statewide, not an individual utility system basis. Nevada assess its NEM aggregate capacity limitations on a percentage of annual statewide peak demand, rather than a fixed statewide capacity amount.

[15] Code of Maryland Regulations (COMAR) 20.50.10.01(A).

Figure 7: State Policies Regarding Aggregate Utility System Capacity Limits
Source: State Statutes and Regulations

1.2.5. Excess Generation Payments and Credits

Regulatory policies associated with the method by which net excess generation ("NEG") will be reimbursed can be controversial. Generally, there are two methods of financial reimbursement: (1) offering a credit for each kWh of NEG (direct credit); or (2) offering payment for each kWh of NEG (direct payment).

Most states use the first method, which is that any net excess generation is carried over to the NEM customer's next bill as a kWh credit. These excess kWh are usually valued at either the utility's retail rate, or an avoided cost rate.[16] In some states, credits accrued during a 12-month period will be paid to the customer via check or billing credit.[17] Other states, including Louisiana, allow a cash payment for outstanding NEG credit balances if the NEM customer discontinues service, while others do not allow for a cash payment at all, and any

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[16] Massachusetts Office of Energy and Environmental Affairs, Net Metering Frequently Asked Questions and Answers. Available at: http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/dpu/net-metering-faqs.html.

[17] Database of State Incentives for Renewables and Energy Efficiency, U.S. Department of Energy. California Incentives/Policies for Renewables & Efficiency, Net Metering. Available at: http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA02R&re=1&ee=0.

unused credit is retained by the utility.[18] The direct payment method of reimbursement usually involves offering a NEM generator some type of pre-defined rate for each kWh of NEG, and then offering a monthly payment to that generator for the excess generation put to a utility's electric distribution grid.[19] Very few states however, reimburse for NEG via direct payment. In New Mexico for example, the utility can choose how to deal with net excess generation. It may credit or pay the customer for NEG at the utility's avoided cost rate; or it may credit the customer for the kWh of NEG from month-to-month and pay for any accrued credits if the customer terminates service.[20]

The next controversy that arises with NEG reimbursement is the method by which the per-unit (per kWh) generation is valued. NEG unit valuation policies can be generally divided into two distinct models: cost-based or incentive-based approaches. Cost-based approaches value generation contributed by the net metered generation system at the utility's avoided cost of energy. This includes all variable production operating costs, such as fuel stock purchases and variable emission control costs, as well as utility purchase power costs. Essentially, cost-based net metering models value all excess generation amounts based on wholesale electric prices, representing the actual avoided costs the excess generation is displacing.

Incentive-based approaches value generation contributed by the net metered generation system at full retail rates, which not only include the utility cost of power, but also all fixed costs of service including capital plant costs such as wires/conductors, poles, meters, and transformers, as well as utility overhead costs such as employee salaries. These fixed costs are not displaced by the customer's self-generation as the customer remains connected to the electric grid. These displaced costs will thus be incorporated into future rate increases, effectively resulting in non-net metered customers subsidizing net metered customers.

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[18] Section 2.04C, Attachment A, LPSC General Order dated July 26, 2013; and Database of State Incentives for Renewables and Energy Efficiency, U.S. Department of Energy. Indiana Incentives/Policies for Renewables & Efficiency, Net Metering. Available at: http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=IN05R&re=1&ee=0.

[19] New Mexico Administrative Code. NMAC 17.9.570.

[20] New Mexico Administrative Code. NMAC 17.9.570.

Figure 8 shows that a large number of states incentivize NEG by crediting it at the retail rate. Kansas, Mississippi, Missouri, Nebraska, and Louisiana value NEG on an avoided cost basis. Georgia, however, utilizes an administratively-determined rate to reimburse excess NEM generation.

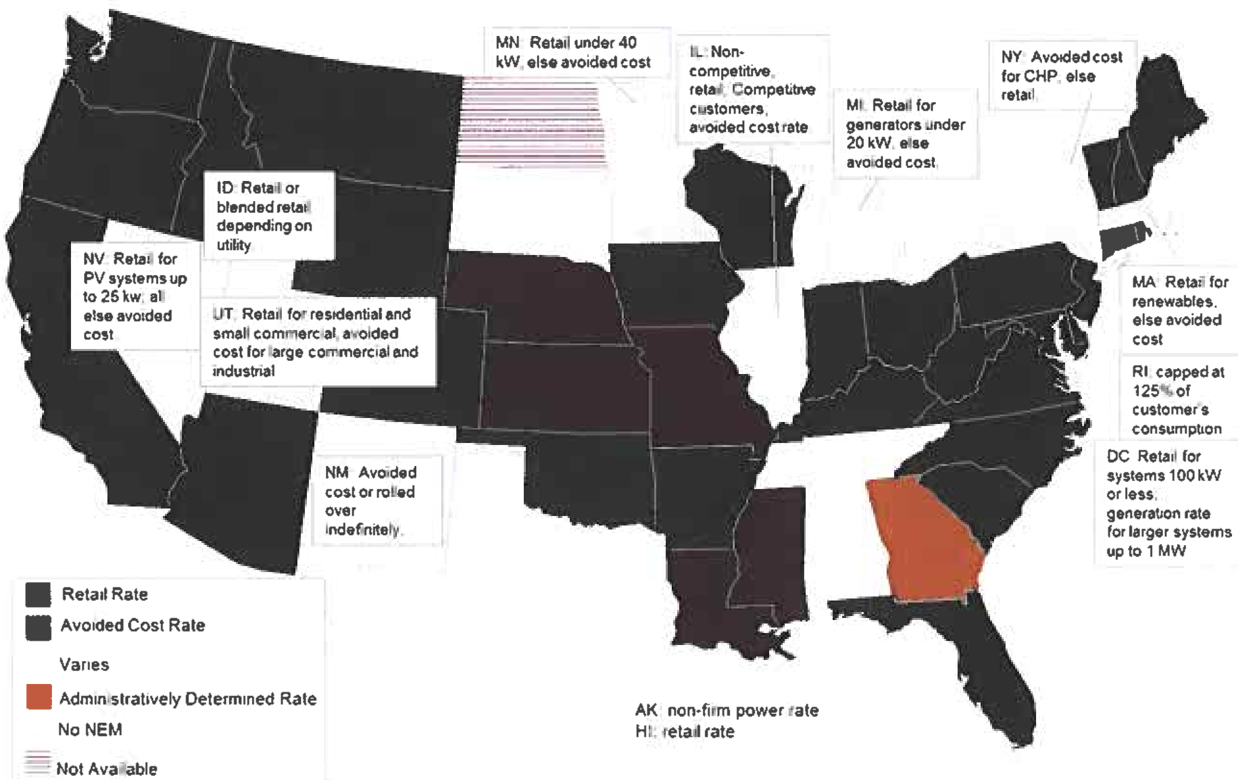

Figure 8: State Policies Regarding Excess Credit Valuation
Source: State Statutes and Regulations

Figure 9 highlights state policies for reimbursement of accrued NEG credits. Only two states, Arizona and Texas, allow permanent banking of NEG credits. Most states, shown below in light green, reset all excess generation credits without compensation annually. So, at the end of an annualized period, any NEG credits in the customer's account expire and are ceded to the utility. In Oregon and Utah, any NEG credits accrued in an NEM customer's account at the end of 12 months are valued at the utility's avoided cost and paid to fund low-income assistance programs.[21]

The remaining states will pay annually accrued NEG credits at either the full retail rate, or an avoided cost rate. Louisiana requires utilities to compensate net metered generators based on the utilities' avoided cost rate

[21] Oregon Administrative Rule 860-039-0060 §1, and Utah Administrative Code 54-15-104 §4(a).

for any excess generation remaining in the final month a customer takes service from the utility, i.e. when a customer closes out his or her account.

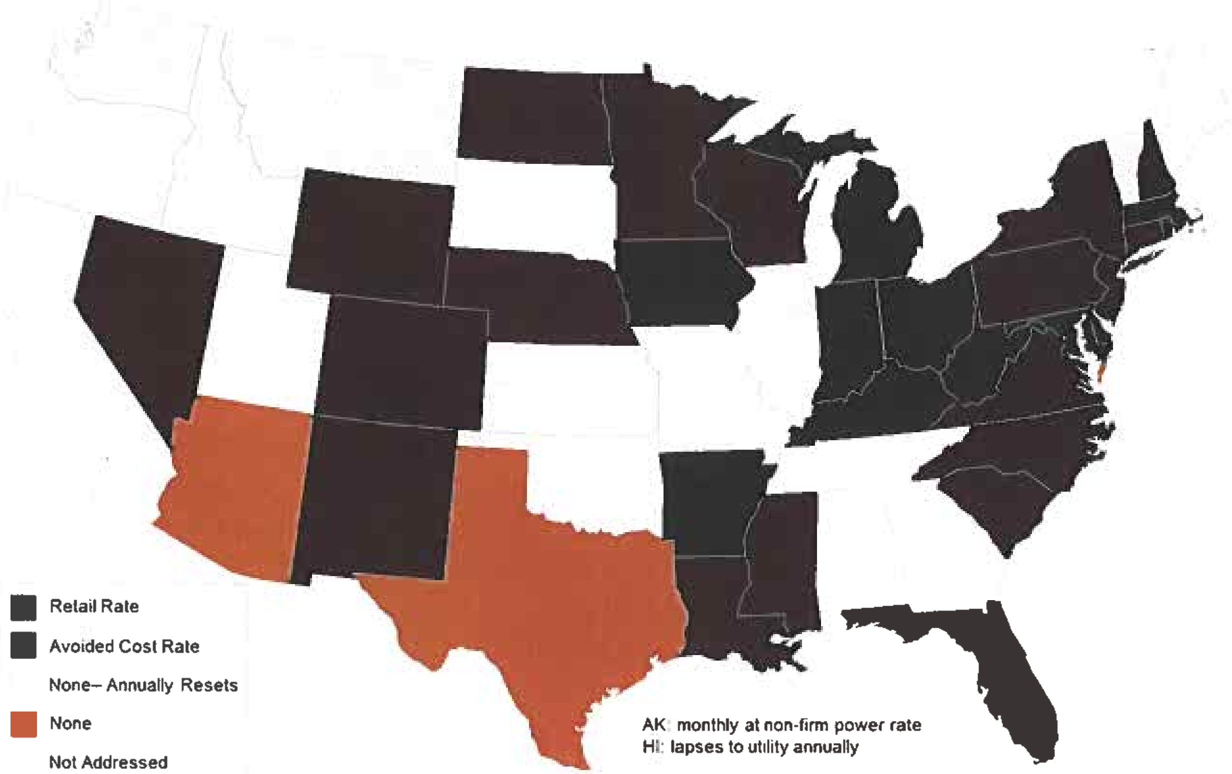

Figure 9: State Policies Regarding Payment of Accrued/Banked NEG Credits
Source: State Statutes and Regulations.

1.2.6. Net Metering Aggregation

Figure 10 shows that 23 states, or approximately 46 percent of jurisdictions with net metering policies, have implemented policies allowing customers to aggregate with one another to attain NEM service. This form of aggregation has been especially popular for solar energy and is often referred to as a "community solar program" or "virtual net metering." NEM aggregation allows individuals to benefit from participating in a solar project (even though the project may not be on the participating customer's property or even contiguous to that property) and attaining potential economies of scale associated with the installation of larger solar systems.

NEM aggregation polices differ substantially from state to state regarding specifics such as eligible customers and tariffs, and geographic limitations for aggregation. For instance, six states with NEM aggregation policies do not allow non-physically connected or "virtual" aggregation (solar farm or community). Furthermore,

states with policies allowing virtual net metering aggregation appear to be concentrated in the Northeast and Mid-Atlantic. Only four states outside of these two regions (Arkansas, California, Colorado, and Washington), allow for virtual net metering aggregation.

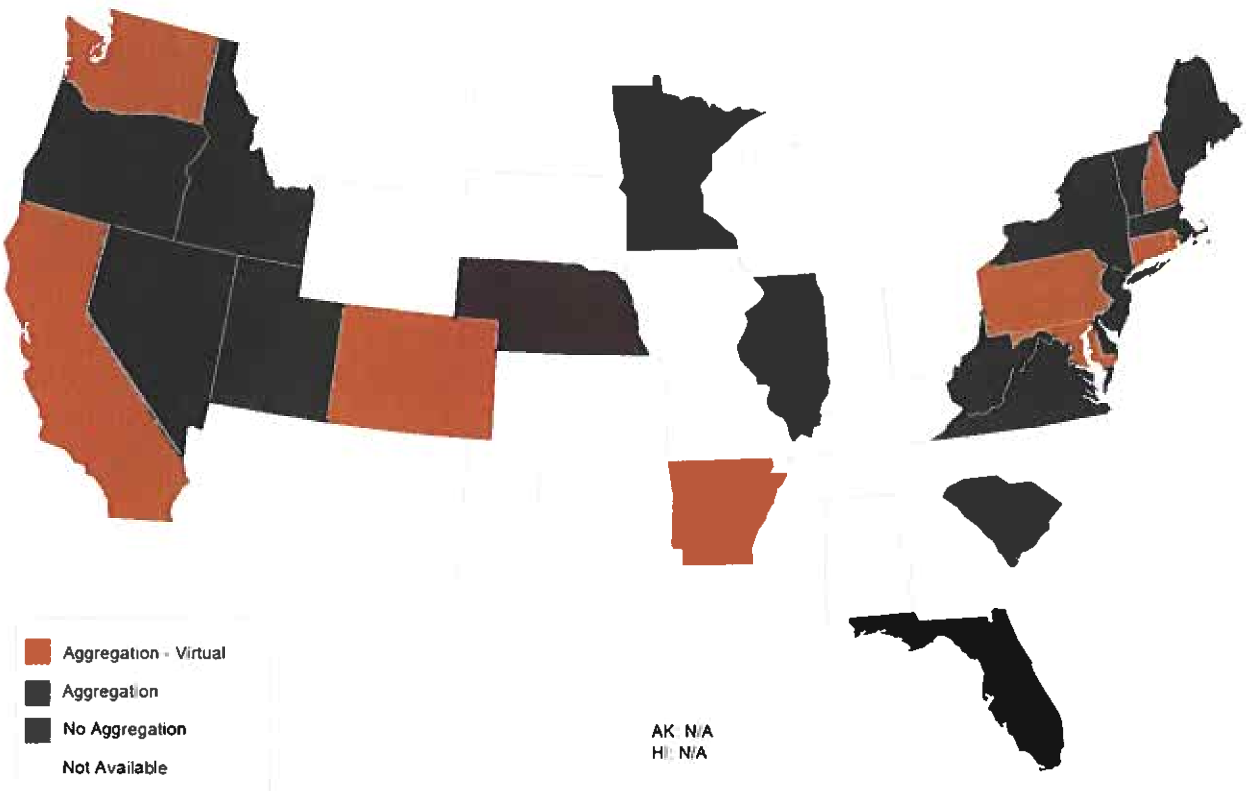

Figure 10: State Policies Regarding Net Energy Metering Aggregation
Source: State Statutes and Regulations

1.3. Solar Panel Cost Trends Supporting NEM Installation Growth

An additional factor leading to the significant development of NEM installations has been the considerable cost decreases associated with solar photovoltaic ("PV") systems, much of which can be attributed to the acceleration of the global photovoltaic module market. As shown in Figure 11, PV exports across the globe have experienced a 53 percent compound annual growth rate from 2000 through 2010, reaching 17 gigawatts ("GW") of PV capacity shipped in 2010. In addition to seeing dramatic growth activity, the global market for PV has shifted over the past decade from country to country. In 2000, the U.S. accounted for 30 percent of global PV

supply, but quickly lost its market share early on.[22] Growth in the market shifted first to Japan, which experienced significant growth due to residential subsidies enacted in the mid-1990s; then to Germany, whose generous feed-in tariff subsidy produced substantial growth in domestic solar demand; and finally to China and Taiwan, which invested heavily in PV manufacturing during the 2006 to 2010 timeframe. In fact, by 2010, China and Taiwan accounted for 53 percent of global PV supply.[23]

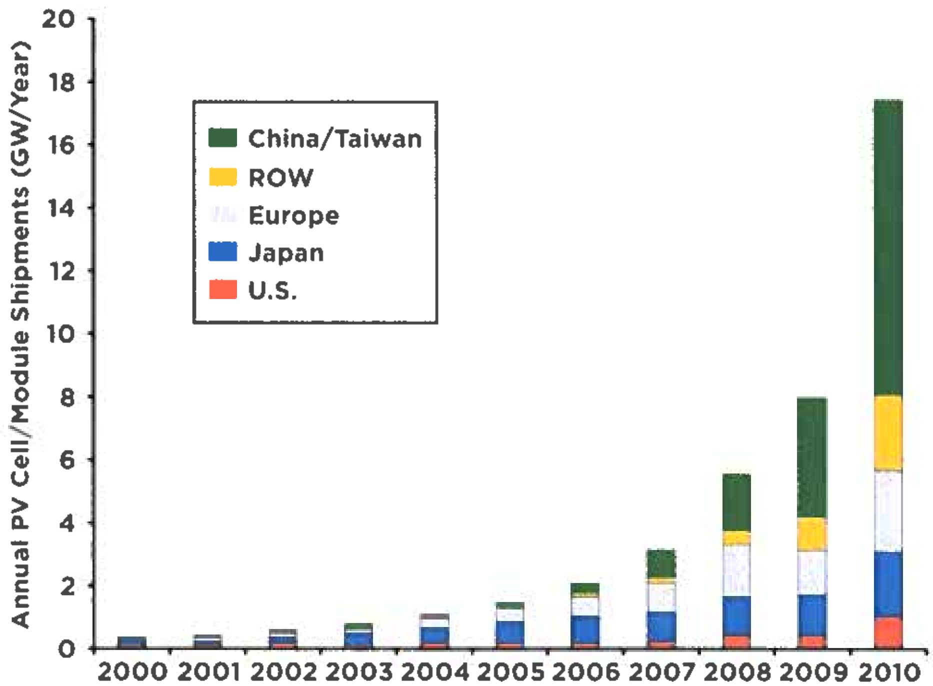

Figure 11: Photovoltaic Module Exports
Source: Afrin, David et. al. 2012. SunShot Vision Study. U.S. Department of Energy, Figure 1-1

The use of Chinese/Taiwanese manufactured PV modules is part of the reason for the decrease in PV prices. Installations using Chinese manufactured PV modules have been consistently less expensive than non-Chinese product installations (Figure 12).[24] However, the massive growth in PV manufacturing around the world has also increased supply and put downward pressure on PV module prices globally.[25]

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[22] Afrin, David et. al. 2012. SunShot Vision Study. U.S. Department of Energy, pp. 3-4.
[23] Afrin, David et. al. 2012. SunShot Vision Study. U.S. Department of Energy, p. 26.
[24] Barbose, Galen et al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, p. 32.
[25] It should be noted that in January 2015, the U.S. International Trade Commission determined that the U.S. PV industry is being materially injured by imports of "certain crystalline silicon photovoltaic products from China and Taiwan that the U.S. Department of Commerce has determined are sold in the United States at less than fair value and are subsidized by the government of China." This decision will result in the U.S. Department of Commerce imposing countervailing duties and antidumping duties on solar imports from

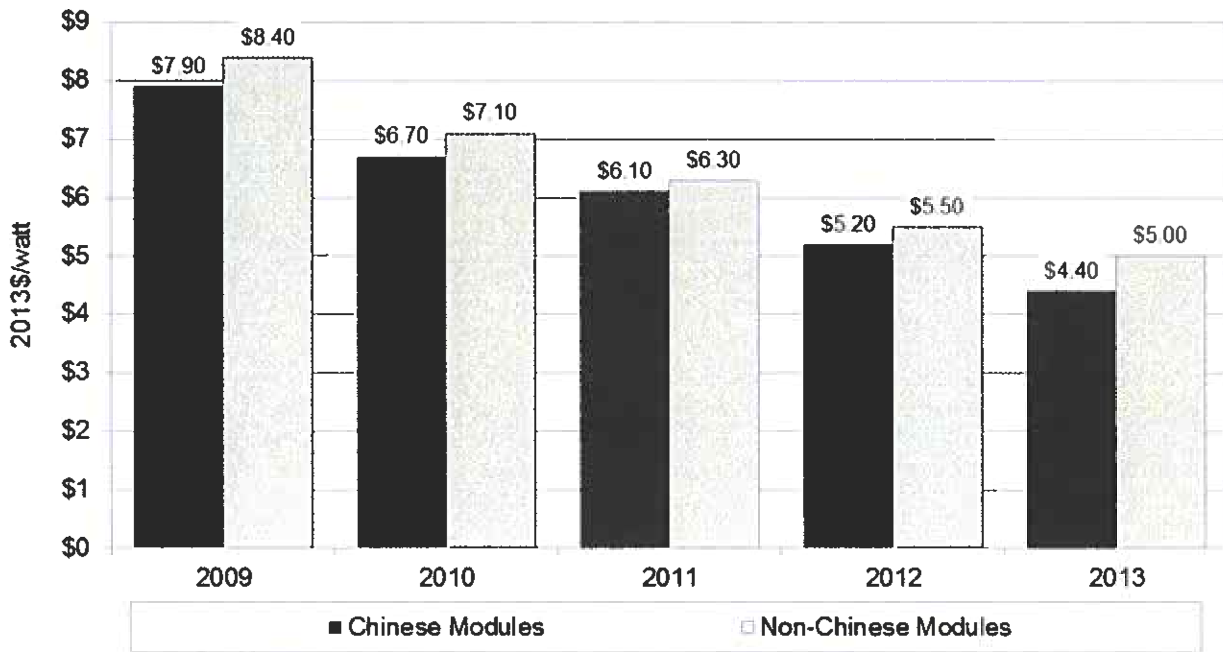

Figure 12: Price Differences between Chinese and non-Chinese Solar PV Installation for <10 kW Systems in the U.S. (2013 $)

Source: Barbose, Galen et. al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, p. 32.

As shown in Figure 13, the cost of a solar PV module in 1998 was slightly less than $5 per watt of DC capacity, a level that held relatively constant until 2007, after which prices plunged to current levels of under $1 per watt. This has affected many domestic solar producers, and U.S. PV manufacturing declined almost 40 percent in the 2011-2012 time period, from 1,161 MW DC capacity in 2011 to 714 MW DC capacity in 2012. Employment in PV-related activities also declined in this period, with the number of full-time equivalent (FTE) employees in PV manufacturing falling from 15,777 FTE in 2011 to 12,575 FTE in 2012[26]. While domestic solar producers have suffered, the increase in imports of less expensive solar modules has resulted in a boon for solar customers.[27]

China. See Pentland, W. 2015. Trade duties on solar imports from China and Taiwan clear final hurdle. Forbes.com. Available at: http://www.forbes.com/sites/williampentland/2015/01/22/trade-duties-on-solar-imports-from-china-and-taiwan-clear-final-hurdle/.

[26] U.S. Energy Information Administration (December 2013), Solar Photovoltaic Cell/Module Shipments Report.

[27] Barbose, Galen et. al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, p. 15.

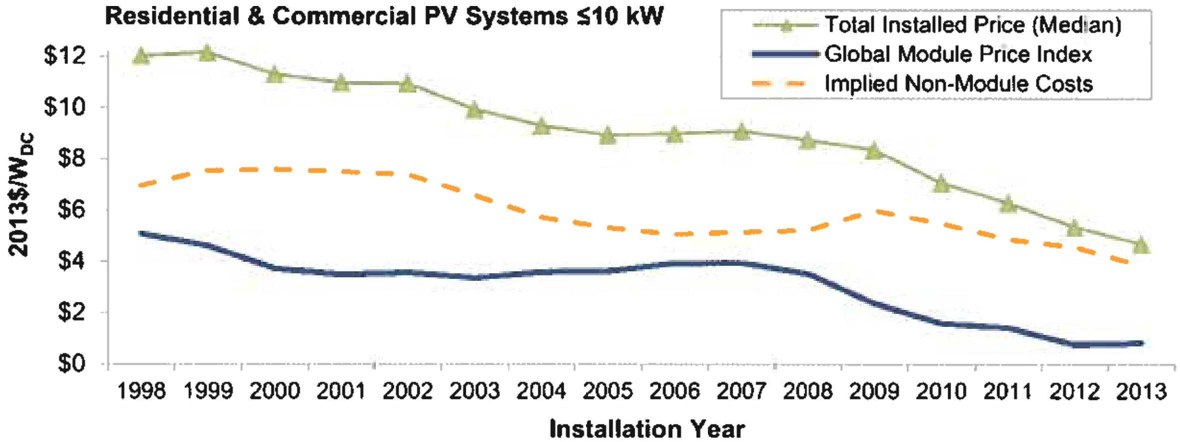

Figure 13: Total Installed PV Price is Decreasing Due to Low Module Costs
Source: Barbose, Galen et. al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, Figure 8.

The total cost of a PV system is made up of the module costs, the inverter costs and "balance of system" or "BOS" costs.[28] As module prices have fallen, BOS costs now account for a large share of the total PV system cost. Figure 14 depicts the cost components for residential, commercial and utility scale systems from 2010 to 2017. As of late 2013, the module and inverter costs were approximately $1 per watt for residential installations while the BOS costs were over $2 per watt.[29] While BOS costs are declining (from approximately $4 per watt for residential systems in 2010 to approximately $2 per watt in 2017) their fall has not been as precipitous as the fall in PV module costs.

[28] Balance of system costs include items such as permitting fees, installation labor, overhead, racking, customer acquisition costs and sale tax.
[29] Fu, Ran et. Al. (September 2017), U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017, U.S. Department of Energy National Renewable Energy Laboratory, Figure ES-1; see also, Feldman, David et. al. (September 2014), Photovoltaic System Pricing Trends, U.S. Department of Energy National Renewable Energy Laboratory, p. 17.

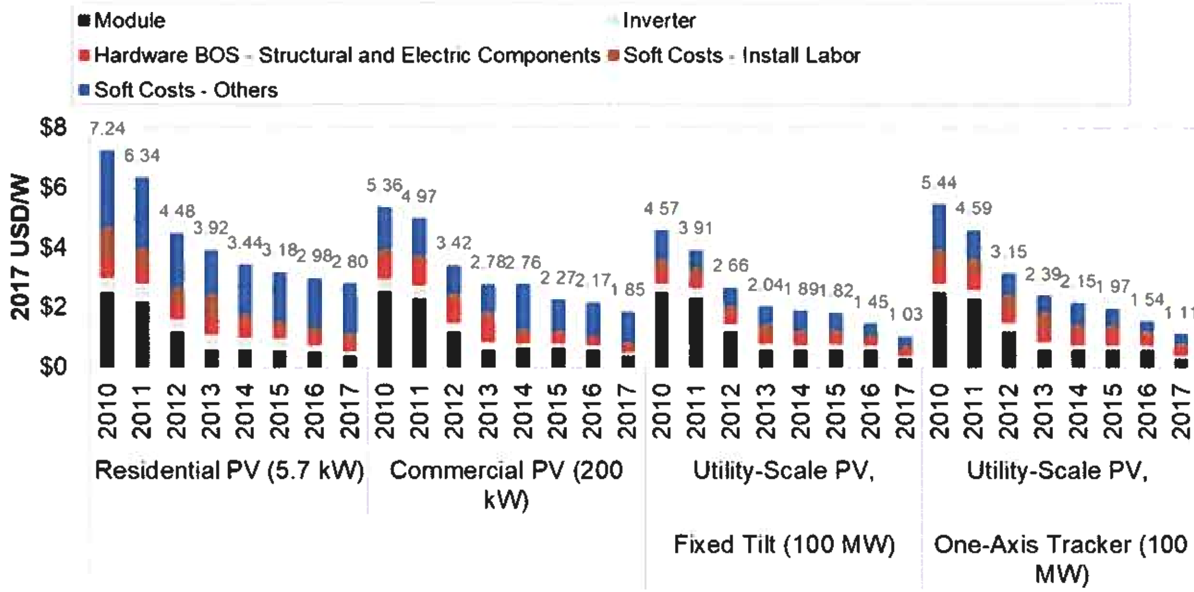

Figure 14: Module, Inverter and Balance of System Costs, 2010-2017
Fu, Ran et. Al. (September 2017), U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017, U.S. Department of Energy National Renewable Energy Laboratory, Figure ES-1.

State policy makers have started to respond to falling module and installed system cost by scaling back government-backed tax incentives and rebates. Figure 15 shows that the average pre-tax rebate for installed systems has decreased to less than $1 per watt from highs of $3 to $7 per watt in the 1998 to 2002 period. It should be noted that the magnitude of this decline is heavily influenced by reductions in California's incentive programs. However, nearly all of the sampled states were found to be reducing PV incentives.[30]

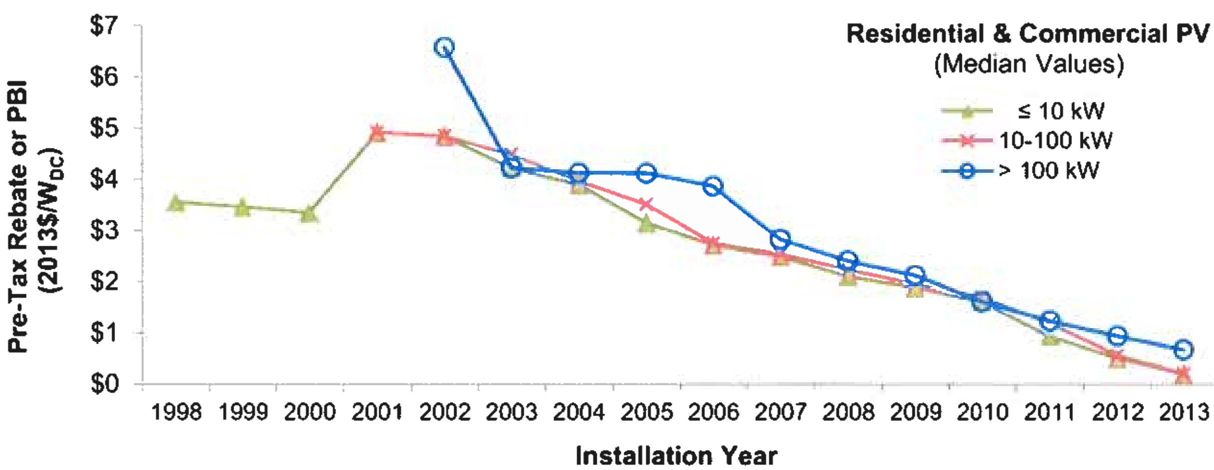

Figure 15: Declining State Rebates and Incentives
Source: Barbose, Galen et. al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, Figure 9.

[30] Barbose, Galen et. al. (September 2014), Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013, U.S. Department of Energy Lawrence Berkeley National Laboratory, p. 17.

1.4. Louisiana Solar NEM Trends

Louisiana saw significant increases in the development of solar NEM installations in the years 2008 through 2014 as shown in Figure 16. While 2010 and 2011 saw less than 1,000 reported solar installations each year, this annual installation rate increased more than five times in just a few short years, with more than 5,000 reported solar installations occurring in 2014. 2015 saw a decrease in the number of reported solar installations, decreasing to 3,377 reported solar installations, slightly more than that seen in 2013. 2016 and 2017 likewise continued this trend, with only 2,364 and 516 reported solar installations, levels previously seen in the State during the period 2011-2013.

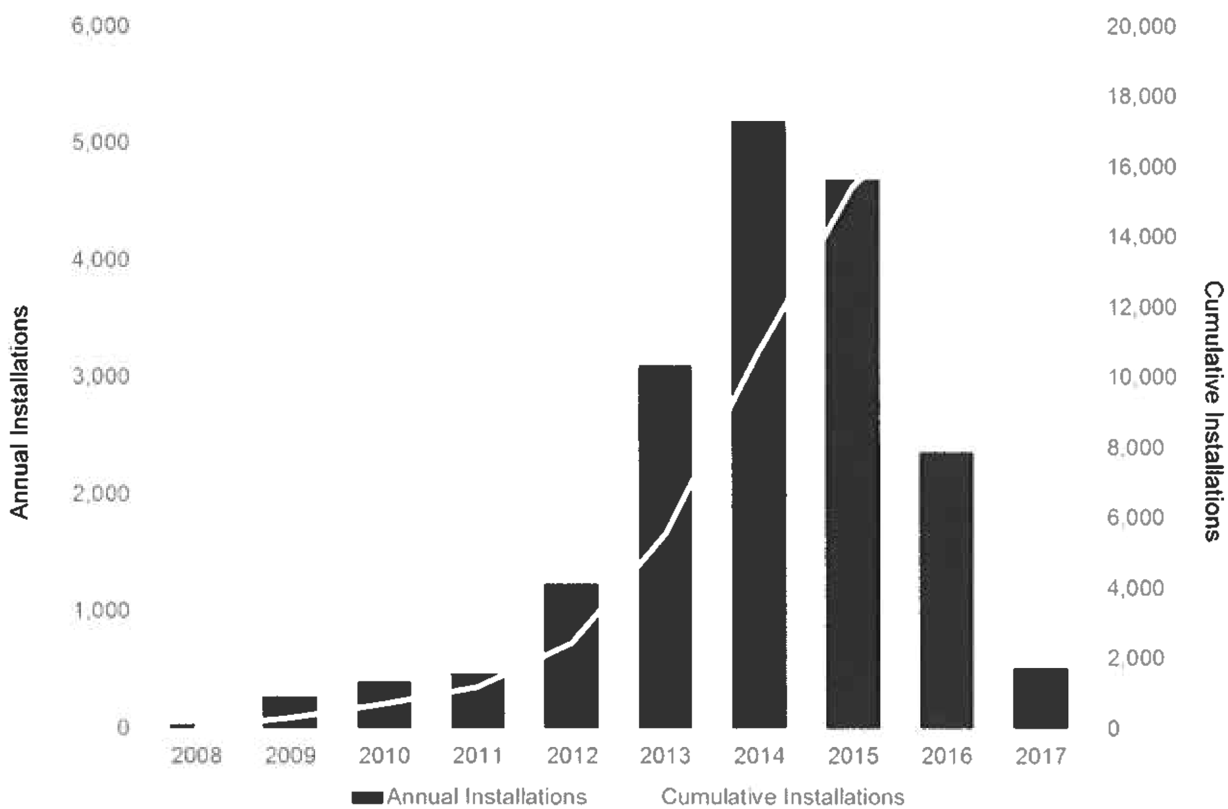

Figure 16: LPSC Jurisdictional NEM Installations
Source: Dismukes, David (2015), *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers*; and LPSC Net Metering Annual Reports.

Figure 17 shows the trends in the development of LPSC-jurisdictional solar NEM capacity from 2008 through 2017. The trends prior to 2015 are comparable in nature to the number of installations presented in

Figure 16. However, 2015 through 2017 have shown a trend towards larger solar systems being installed in the state relative to that previously seen in 2013 and 2014. Annual installed capacity grew from approximately than 1.5 MWs of installation in 2008, to more than 30.5 MWs of installed capacity in 2015, falling to slightly less than 16 MWs in 2016, and approximately 4.9 MWs in 2017. On a cumulative basis, Louisiana had more than 113 MWs of installed jurisdictional solar NEM capacity by year-end 2017, compared to only approximately 1.6 MWs of installed jurisdictional capacity in 2008.

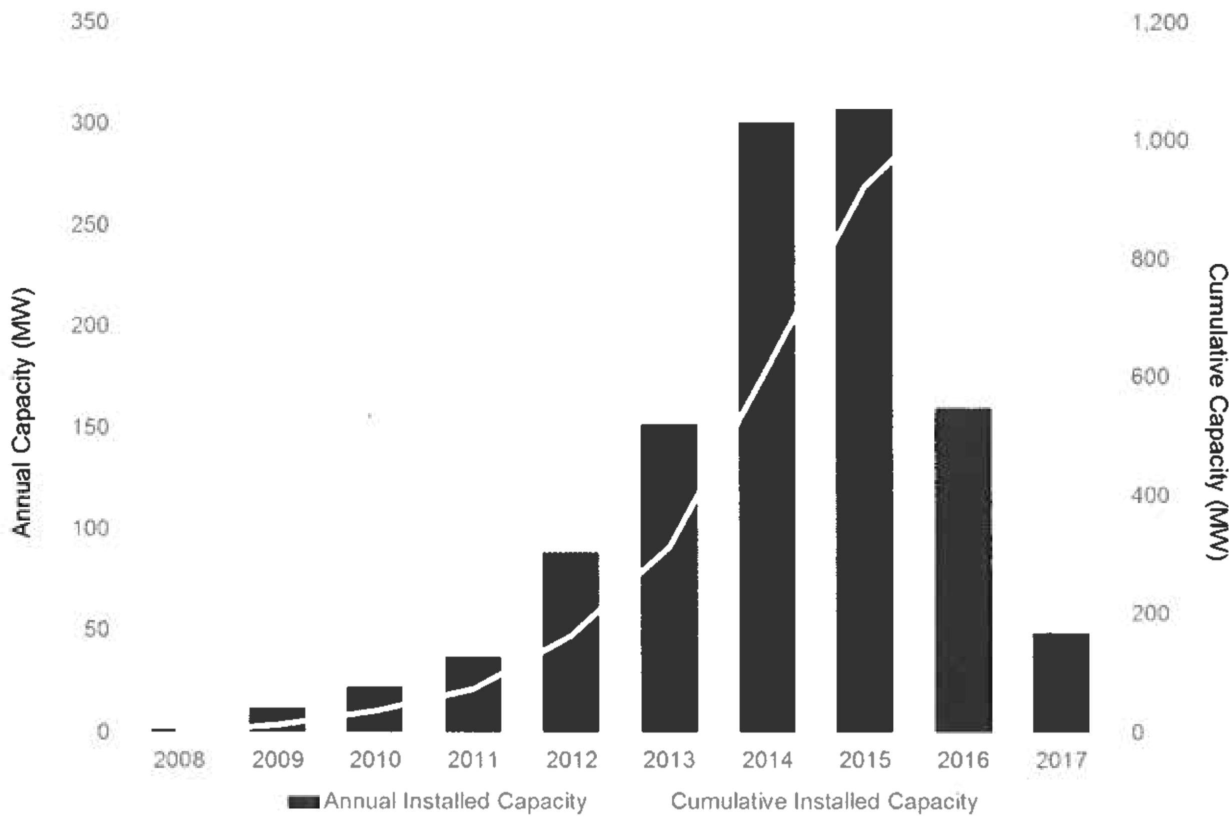

Figure 17: LPSC Jurisdictional NEM Capacity
Source: Dismukes, David (2015), *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers*; and LPSC Net Metering Annual Reports.

Figure 18 presents the trends in the average size of LPSC-jurisdictional solar NEM installations in the state from 2008 through 2017. In 2008, the average size for jurisdictional solar NEM installations was relatively small at around 3.6 kW. This increased over the next several years, until 2012 when the average size of a jurisdictional NEM installation peaked at 7.1 kW. Average solar installation sizes fell significantly from 2012 to 2013, but have since grown again, such that the average size of a system installed in 2015 and 2016 is 6.6 and 6.8

kWs, respectively. 2017 has seen even greater movement towards larger systems, with the average installed system being 9.5 kWs in size, larger than even average system sizes during 2011 and 2012.

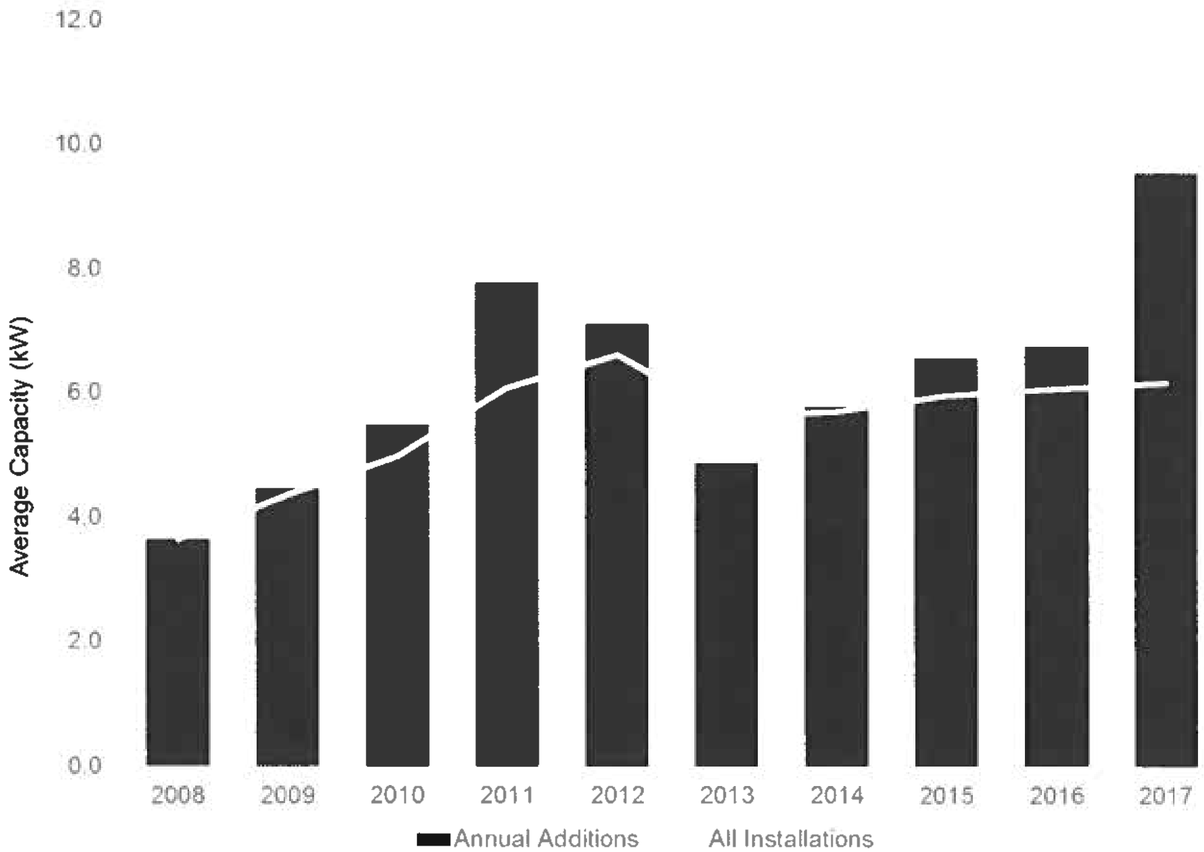

Figure 18: Total Louisiana NEM Average Capacity
Source: Dismukes, David (2015), *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers*; and LPSC Net Metering Annual Reports.

Figure 19 summarizes the trends in LPSC-jurisdictional solar NEM generation. The historic trends are comparable to those shown for solar NEM solar capacity development. Overall, solar NEM generation has been growing at a considerable rate throughout the state, a rate that was increasing through 2014. Since 2014, solar NEM generation, while still growing in the state, has been growing at a decreasing pace year on year.

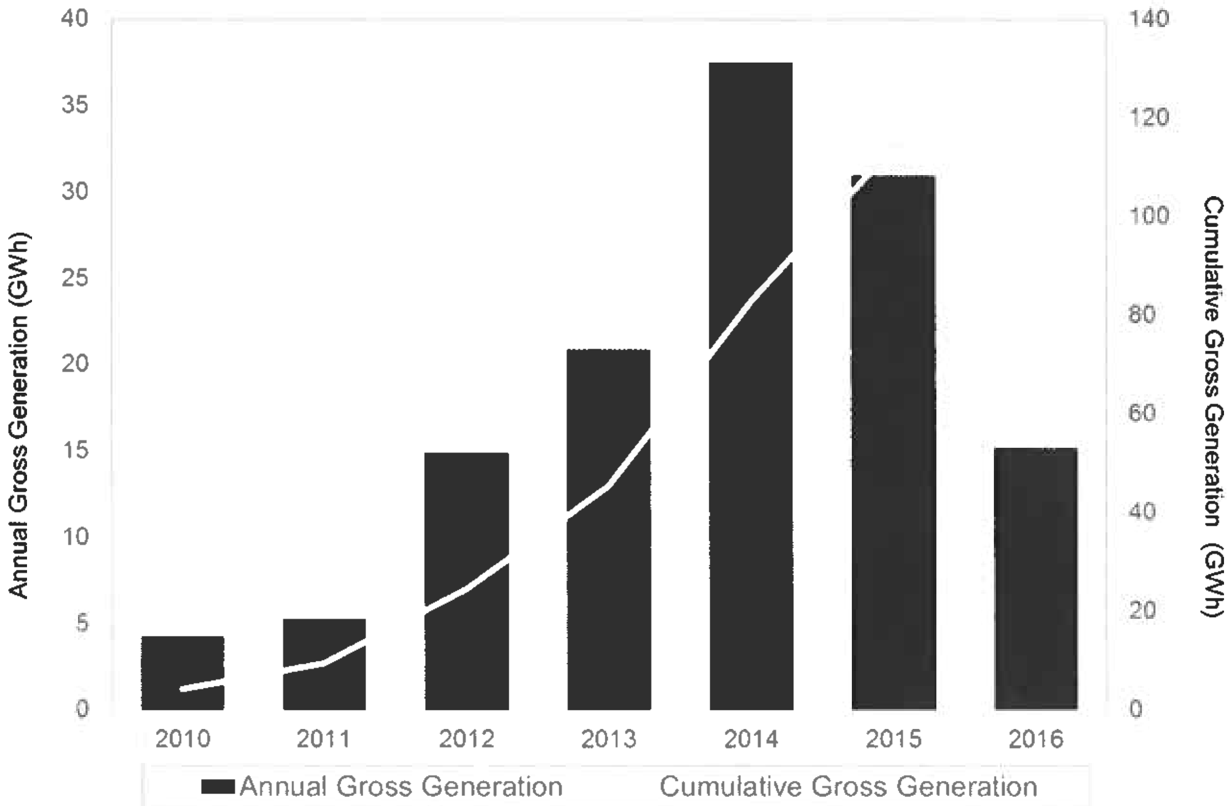

Figure 19: Estimated Louisiana NEM Gross Generation
Note: 2010 data includes installations from prior years.

Figure 20 shows the concentration of solar NEM capacity and generation relative to statewide totals. Both solar NEM capacity and gross generation have been increasing rapidly over the past several years but, in the absolute, still comprise a relatively small share of total jurisdictional capacity and generation. By year-end 2016, solar generation is estimated to comprise less than 0.40 percent of state electric generation capacity and approximately 0.12 percent of state electric generation.

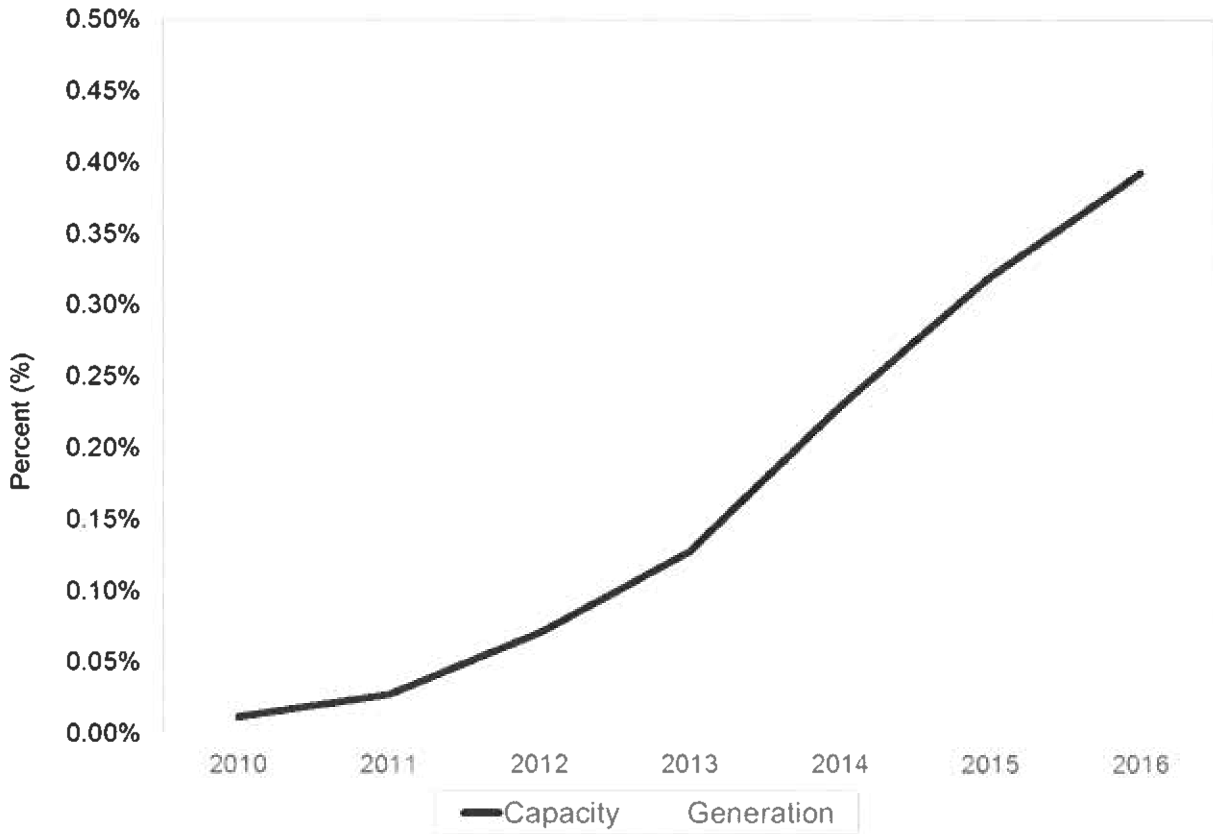

Figure 20: NEM Capacity and Generation as a Share of Total State Capacity and Generation
Note: 2010 data includes information from prior years.

Section II

SUMMARY OF PARTY COMMENTS

Section II. Summary of Party Comments

2.1. Summary of First Round Comments

2.1.1. General Position on Commission Interim Rule

Generally, Louisiana utilities ELL, Cleco, ALEC, and SWEPCO all expressed opposition to the NEM interim Rule enacted by the Commission in November 2016, while PosiGen, AAE, and GSREIA expressed support for the Interim Rule. The Sierra Club expressed dissatisfaction with the Interim Rule, though for reasons opposite the utilities.

ELL and CLECO stated that the Interim Rule, which only provide avoided cost credits to "net excess generation", will make no difference going forward in mitigating the cross-subsidization due to full retail crediting of net metering generation.[31] SWEPCO, also opposed to the Rule, warned that many net metering customers have paid zero dollars in some months for the energy they purchase from SWEPCO.[32] Likewise, ALEC also stated opposition to the Interim Rule.[33]

PosiGen claimed that the current NEM Rule allow low-to-moderate income households an opportunity to manage financial stresses from their energy bills.[34] Contrary to SWEPCO's allegation, PosiGen claimed that only a handful of its customers have zeroed out their usage.[35] AAE also supported keeping the current Rule unless time and location data is analyzed and provides a cause for significant change.[36] AAE maintained that current full retail NEM customers should be grandfathered in at full retail rates, stating that it did not share the utilities' concern regarding cross-subsidization, claiming that cross-subsidization has yet to be verified in Louisiana.[37] Likewise, GSREIA supported keeping in place the pre-cap full retail and post-cap Phase I NEM Rule, as it asserted no data existed justifying changes to this Rule, while existing Commission Rule were consistent with

[31] ELL's Comments in Response to Staff's Initial Request for Comments (Phase II) Regarding Proposed Modifications to the Commission's Current Net Metering Rules, at 5; and Phase II Comments of CLECO Power LLC, at 2.
[32] Comments on Behalf of Southwestern Electric Power Company, at 3.
[33] Comments of the Association of Louisiana Electric Cooperatives, Inc, at 1.
[34] PosiGen's Initial Comments Regarding Net Metering Phase II, at 3.
[35] PosiGen's Initial Comments Regarding Net Metering Phase II, at 1.
[36] The Alliance for Affordable Energy's Phase II Comments, at 2.
[37] The Alliance for Affordable Energy's Phase II Comments, at 3.

policies in other states.[38] In fact, GSREIA asserted that the lack of data availability meant that some net metering customers would be paying more than their fair share of costs with changes in existing Commission Rule.[39] Finally, GSREIA also stated its belief that then-current net metering policies should be grandfathered for at least 20 years.[40]

Consistent with its overall position being non-supportive of prior Commission NEM Rule, the Sierra Club requested that the Commission maintain, at a minimum, full retail net metering as it existed prior to a utility reaching the 0.5 percent cap on net metering penetration. The Sierra Club asserted that there was no evidence that this "full net metering" lead to cross-subsidization,[41] instead positing that the policy lead to benefits, including: reductions in demand, reductions in stress on the transmission and distribution system, and encouragement of private installation of additional generation capacity.[42] The Sierra Club further contended that existing net metering customers should be grandfathered under then-existing Rule, and that the Commission should reevaluate the existing 0.5 percent cap on net metering penetration.

2.1.2. Positions on Two-Channel Billing

ELL stated that it had implemented a form of two-channel billing for net metering customers who filed an application on or after January 1, 2016.[43] Subsequently, the company conducted an analysis comparing full retail and 2-channel billing using 311 residential customers and found that full retail crediting would have lowered the average customer's bill by $10.57 in the month of December, 2016.[44] Because of this, ELL stated that it was strongly supportive of two-channel billing and believed that two-channel billing correctly addressed the difference in value between excess energy delivered to the grid and energy from the grid.[45]

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[38] Initial Comments of the Gulf States Renewable Energy Industries Association, at 1.
[39] Initial Comments of the Gulf States Renewable Energy Industries Association, at 4.
[40] Initial Comments of the Gulf States Renewable Energy Industries Association, at 9.
[41] Sierra Club Response to Initial Request for Comments, Phase II Rulemaking, at 2.
[42] Sierra Club Response to Initial Request for Comments, Phase II Rulemaking, at 2.
[43] ELL's Comments in Response to Staff's Initial Request for Comments (Phase II) Regarding Proposed Modifications to the Commission's Current Net Metering Rules, at 2.
[44] ELL's Comments in Response to Staff's Initial Request for Comments (Phase II) Regarding Proposed Modifications to the Commission's Current Net Metering Rules, at 4.
[45] ELL's Comments in Response to Staff's Initial Request for Comments (Phase II) Regarding Proposed Modifications to the Commission's Current Net Metering Rules, at 12.

CLECO, ALEC, and SWEPCO also expressed support for two-channel billing. CLECO stated that the proposed Rule would ensure that the utility is compensated for costs actually incurred, proposing a modified two-channel billing system in which the net excess credit is priced at the company's average avoided cost and recovered through its monthly fuel adjustment clause.[46] ALEC supported a full two-channel billing system where all energy exported to the cooperative's system is credited at the utility's avoided cost rate.[47] SWEPCO likewise proposed crediting the value of each billing channel separately, netting the two channels to arrive at the customer's final bill.[48]

AAE stated that the proposed two-channel billing is, "a policy developed to benefit utilities."[49] Similarly, GSREA stated that two-channel billing is "designed to maximize financial gain for the utility."[50] The Sierra Club provided a more detailed critique of the proposed policy, asserting that two-channel billing would make it difficult for customers to understand and determine with certainty the economic value and payback of a net metered facility. The Sierra Club stated that this would require the installation of more expensive metering technology, updates to utility billing systems, and increased customer service costs.[51]

While not recommending support for the policy,[52] the Sierra Club argued that if the Commission chose to adopt a two channel billing regime, the Commission should include an "adder" to be applied to a given utility's avoided cost rate to account for the public benefits of distributed generation systems, similar to the policy adopted by the Mississippi Public Service Commission.[53] The Sierra Club also argued that an additional adder further increasing the compensation rate for energy exported to the electric grid should be applied to distributed generation systems owned by low-income customers.[54]

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[46] Phase II Comments of CLECO Power LLC, at 3.
[47] Comments of the Association of Louisiana Electric Cooperatives, Inc, at 2.
[48] Comments on Behalf of Southwestern Electric Power Company, at 4.
[49] The Alliance for Affordable Energy's Phase II Comments, at 4.
[50] Initial Comments of the Gulf States Renewable Energy Industries Association, at 5.
[51] Sierra Club Response to Initial Request for Comments, Phase II Rulemaking, at 8.
[52] Ibid.
[53] Sierra Club Response to Initial Request for Comments, Phase II Rulemaking, at 9.
[54] Ibid.

2.1.3. Alternative Rate Structures

In its request for comments, the Commission requested comments as to whether other retail service offerings could be implemented to alleviate concerns regarding distributed generation valuation. ELL commented that it believed that the time-of-use ("TOU") rate structure, suggested by the Commission as an example of alternative rate structures, would require both additional changes to the Company's rate structure and installation of Advanced Metering Infrastructure ("AMI").[55] ALEC likewise commented that confusion might ensue if such alternative rate structures were implemented as an alternative to two-channel billing.[56]

SWEPCO, on the other hand, proposed a variety of alternatives to existing rate structures in its comments. While generally supportive of the idea of TOU rates, the utility stated that it might be necessary in the future to implement residential demand charges for the purposes of recovering fixed costs that are currently recovered through volumetric rates. SWEPCO however stated that, under such a proposal, it may not be necessary to implement a two channel billing structure for net metering,[57] and, in fact, the utility recommended the implementation of residential demand charges even without the implementation of TOU rates.[58] Finally, SWEPCO also suggested a separate rate class be created for net metering customers with the explicit goal of ensuring that all costs to provide service to such customers are recovered through rates without cross-subsidization.[59]

PosiGen stated that it supported the increased deployment of AMI in Louisiana, believing that the systems will ultimately increase the value of distributed generation systems.[60] PosiGen also asserted that the use of smart inverter technologies will increase grid hardening and suggested the sale of Renewable Energy Credits ("RECs") as a way of providing additional revenue streams to customers with renewable distributed generation systems.[61]

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[55] ELL's Comments in Response to Staff's Initial Request for Comments (Phase II) Regarding Proposed Modifications to the Commission's Current Net Metering Rules, at 14-15.
[56] Comments of the Association of Louisiana Electric Cooperatives, Inc, at 5.
[57] Comments on Behalf of Southwestern Electric Power Company, at 5.
[58] Ibid.
[59] Ibid.
[60] PosiGen's Initial Comments Regarding Net Metering Phase II, at 4.
[61] Ibid.

AAE expressed support for the use of increasingly granular load data provided by the introduction of AMI, stating that such data will assist in the appropriate valuation of energy provided by distributed generation systems.[62] AAE stated that TOU energy pricing could offer additional benefits, such as incentivizing support by distributed generation systems for the wholesale bulk power market during peak hours when resources are strained. AAE stated that the alignment of compensation to wholesale markets, and the granular data from AMI systems, may incentivize solar installers to optimize solar panel placement such that generation corresponds to market tendencies.[63] Beyond TOU pricing, AAE also suggested that an additional credit be provided to customers who are located in known distribution pockets or other areas that experience congestion.[64] A final suggestion by AAE proposed the support for virtual net metering, which would allow ratepayers without the means or facilities to support solar panels, to benefit from net metering credits.[65]

GRSEIA in its comments did not list any potential mechanisms for alternative retail service offerings, though it stated that it was generally supportive of implementing such mechanisms along with net metering.[66] However, the organization does not support the replacement of existing net metering service offerings with alternative rate structures.[67]

The Sierra Club asserted that there is no evidence that utilities are not recovering their full cost of service from net metering customers currently, and thus the organization opposes the implementation of any demand or fixed charges for net metering customers. It claims that high fixed or demand charges do not necessarily recover costs from net metering customers in a manner that is more in line with cost causation,[68] and only serve the purpose of undermining the economic value of distributed generation.[69] However, the organization stated that it

[62] The Alliance for Affordable Energy's Phase II Comments, at 5.
[63] Ibid.
[64] Ibid.
[65] The Alliance for Affordable Energy's Phase II Comments, at 6.
[66] Initial Comments of the Gulf States Renewable Energy Industries Association, at 5-6.
[67] Ibid.
[68] Sierra Club Response to Initial Request for Comments, Phase II Rulemaking, at 10.
[69] Sierra Club Response to Initial Request for Comments, Phase II Rulemaking, at 11.

is not opposed to a moderate minimum bill designed to ensure that all customers are contributing to a utility's fixed distribution costs.[70]

2.1.4. Restrictions on the Size of Net Metering Facilities

ELL stated that it believes that DER systems are generally already installed when the company receives a net metering application, and therefore ensuring that these systems are not oversized relative to the customer's energy usage is currently not feasible.[71] Furthermore, customers, rather than the Commission or utility, are ultimately in control of their energy usage.[72] ELL provided the example of a customer on its system who was grandfathered under previous Commission policy providing full retail net metering and now receive excess generation credits monthly that are continually being carried over. In other words, the customer in question only receives a minimum charge from the Company each month.[73] ALEC similarly stated that the need for issuing additional size restrictions on net metering systems will be mostly minimized with the implementation of two channel billing.[74]

Unlike ELL or ALEC, CLECO and SWEPCO stated that they are supportive of size restrictions to distributed generation facilities, with CLECO supporting a capacity restriction based upon an average use study, and SWEPCO supporting a lowering of the current 25 kW capacity maximum to 10 kW.[75] SWEPCO furthermore recommends that net metering customers receive no compensation for any production over the customer's own consumption. Finally, SWEPCO raised the issue of customers who add additional panels without disclosure as required by the Commission, and the potential problems this causes to utility distribution systems.

AAE stated that it does not support any restrictions on the size of new net metering facilities, believing that customers should be able to size facilities according to their needs which may change with the weather and

[70] Ibid.
[71] ELL's Comments in Response to Staff's Initial Request for Comments (Phase II) Regarding Proposed Modifications to the Commission's Current Net Metering Rules, at 15.
[72] Ibid.
[73] ELL's Comments in Response to Staff's Initial Request for Comments (Phase II) Regarding Proposed Modifications to the Commission's Current Net Metering Rules, at 15-16.
[74] Comments of the Association of Louisiana Electric Cooperatives, Inc, at 5.
[75] Phase II Comments of CLECO Power LLC, at 4; and Comments on Behalf of Southwestern Electric Power Company, at 5.

seasons.[76] GSREIA stated it generally was not unsupportive of sizing restrictions, but believes that sizing restrictions should not be implemented for the explicit purpose of eliminating net excess generation.[77] The organization proposed a limit of 120% of the previous 12-month period for residential customers and at least two MW for commercial systems.[78] Sierra Club likewise stated that it supports a size restriction based upon the customer's annual usage.[79]

2.2. Summary of Second Round Comments

2.2.1. Evidentiary Issues

a. **Party Position:** Many commenters representing the solar industry expressed concerns that the proposed Rule is premature and unsupportable with record evidence. The Sierra Club, for instance, claims that the proposed Rule revisions are not legally supportable by existing record evidence[80] and claims that the Rule is not supported by a cost-benefit analysis ("CBA"). Sierra Club goes further by noting that the prior net metering CBA, sponsored by the LSPC Staff (hereafter, "Staff Cost-Benefit Report"),[81] completed in 2015, was never formally "approved" by the Commission.[82] The Sierra Club further claims that "there is a notable analytical gap in the record [on net metering] before the Commission."[83]

The Sierra Club's evidentiary arguments were echoed by AAE and PosiGen. AAE claims that there are several publicly-available models that can be used to determine the value and costs of net metering for both participating and non-participating customers. AAE further claims that failure to utilize any CBA makes the Rule "unjustified and unsupported."[84] AAE furthermore argues that the previous Staff Cost-Benefit Report found a net-cost for distributed solar net metering only after incorporating the impact of the State tax credit as a cost to

[76] The Alliance for Affordable Energy's Phase II Comments, at 6.
[77] Initial Comments of the Gulf States Renewable Energy Industries Association, at 6.
[78] Initial Comments of the Gulf States Renewable Energy Industries Association, at 7.
[79] Sierra Club Response to Initial Request for Comments, Phase II Rulemaking, at 12.
[80] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 1.
[81] David E. Dismukes. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers.* Final Report Prepared on the Behalf of the Louisiana Public Service Commission. September 23.
[82] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 2.
[83] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 2.
[84] Comments on Behalf of the Alliance for Affordable Energy, at 1.

the program. AAE goes further in claiming that since this tax credit has since expired, the results from the Staff Cost-Benefit Report would likely result in a small financial ratepayer impact associated with solar energy development.[85]

PosiGen argues that the proposed Rule changes are "arbitrary and capricious," and questions what it claims is a "rush" to prepare, modify, and change the Commission's existing Rule, which, apparently, are unnecessary given the slow-down in current net metering installations.[86] PosiGen also echoes Sierra and AAE in claiming that Rule cannot be adopted without an adequate CBA.[87]

GSREIA takes a position similar in nature to other parties supporting solar development by arguing that the Commission's own actions over the past year or more have created a high degree of regulatory uncertainty for solar developers and led to the current situation where solar installations have slowed. According to GSREIA, Commission net metering policies, and presumably not changes in Louisiana tax policies, have been the more important policy driver in motivating behind-the-meter solar installations throughout Louisiana. GSREIA argues that the Staff's proposed Rule will exacerbate what is already a state of "high regulatory uncertainty" by opening the door to potentially "onerous fees" and "abuses of consumer rights."[88] GSREIA argues that the Commission should not move forward with what it defines as a "rushed and poorly informed" Staff rule proposal, noting, as an example, that a similar policy change to NEM policies in Nevada resulted in the loss of 2,600 jobs within weeks in the renewable energy sector.[89]

No other parties raised any issues, nor offered any comments on the procedural issues associated with the proposed Staff Rule nor the rulemaking and comment process. Utilities and industrial intervenors were silent on these issues.

[85] Comments on Behalf of the Alliance for Affordable Energy, at 2.
[86] Comments of PosiGen of Louisiana, LLC on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 2.
[87] Comments of PosiGen of Louisiana, LLC on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 2.
[88] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 2.
[89] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 3.

b. **Staff Response:** The issues raised by the parties supporting solar in this proceeding can be summarized as the following:

- The Commission cannot develop a rule without conducting a CBA.
- The Commission needs to "approve" a CBA in order to approve a proposed rule.
- The current proposed rulemaking process, that attempts to update the Commission's existing net metering Rule, is "arbitrary and capricious."
- The Commission has been creating, and continues to create, regulatory uncertainty for Louisiana solar developers and the adoption of the proposed rule will lead to additional regulatory uncertainty.

Staff finds that these aforementioned assertions are largely incorrect or are without merit.

First, the parties supporting increased solar development incorrectly assert that the Commission cannot enter into a rulemaking proceeding, and adopt proposed Rule, without a CBA. The Louisiana Constitution grants the Commission plenary authority to adopt rules based upon its own judgment regarding what "is" and what "is not" in the public interest. Article IV § 21(B) of the Louisiana Constitution provides:[90]

> [T]he commission shall regulate all common carriers and public utilities and have such other regulatory authority as provided by law. It shall adopt and enforce reasonable rules, regulations, and procedures necessary for the discharge of its duties, and shall have other powers and perform other duties as provided by law.

In *Southern Bell Telephone and Telegraph Company v. Louisiana Public Service Commission*, 232 La. 446, 94 So.2d 431, 438, the Supreme Court of Louisiana held that there is no prescribed formula for the fixing of "reasonable and just" rates; that it is the result reached, not the method employed, which is controlling. The Court followed the precedent established by the United States Supreme Court in *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333, to the effect that the fixing of "just and reasonable" rates involves a balancing of the investor and the consumer interests.[91]

> We held in *Federal Power Commission v. Natural Gas Pipeline Co., supra,* that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its ratemaking function moreover, involves the making of "pragmatic adjustments." And when the Commission's order is challenged in the courts, the question is whether that order, "viewed in its entirety," meets the requirements of the Act. <u>Under the statutory standard of "just and</u>

[90] La. Const. Art. IV, § 21.
[91] Morehouse Natural Gas Co. v. La. Pub. Serv. Comm'n, 242 La. 985, 140 So. 2d 646 (1962).

reasonable," it is the results reached, not the method employed, which is controlling. It is not theory, but the impact of the rate order, which counts.[92]

In addition, the Louisiana Renewable Energy Development Act ("LREDA"), which codifies Louisiana net metering policy, does not reference the use of CBA, nor does it explicitly require, nor implicitly suggest that a CBA is required in order to develop net metering rules. In fact, the statute gives the Commission broad latitude, much like the Constitution itself, in defining a net metering Rule, even going so far as to explicitly state: "[n]othing in this Chapter shall derogate from the commission's constitutional authority to regulate, as applicable, all common carriers and public utilities, particularly the authority to implement rules, regulation, and tariffs to ensure that neither an electric utility nor its ratepayers shall be adversely affected."[93] No reading of the plain intent of the statute suggests that a CBA is required for the Commission to adopt a net metering Rule.

Putting aside the Commission's Constitutional grant of authority, the claim that no CBA has been conducted is factually incorrect. The Commission Staff sponsored a comprehensive cost-benefit study, as well as subjected that study to public comment and scrutiny. The final Staff Cost-Benefit Report, dated September 23, 2015, spanned over 187 pages. The Staff Report also included several voluminous technical appendices that, collectively spanned over 100 pages. In total, the Staff Cost-Benefit Report is almost 300 pages in length, including pages of technical information and sourcing. The Staff Cost-Benefit Report was comprehensive in its coverage of state-specific and national net metering trends and policy issues. More importantly, Staff addressed the comments and concerns raised by all parties, in detail, as outlined in Appendix C of the Final Staff Cost-Benefit Report. This appendix itself spanned over 75 pages and addressed each parties' comments on an issue-by-issue basis.

The Sierra Club, as noted earlier, suggests that there is a significantly "analytic gap" in the development of the Staff Proposed Rule. This is simply not the case since the Staff Cost Benefit Report provides considerable analytic detail showing that the Commission's past net metering policies have resulted in ratepayer costs in the form of considerable cross-subsidies. Table 1, below, summarizes these findings.

[92] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 602 (1944), *emphasis added and internal citations removed.*
[93] Louisiana Revised Statutes, Chapter 50, Section 3063(C), *emphasis added.*

Table 1: Summary of Staff Cost-Benefit Report Findings

	Economic Impacts							
		Direct		Indirect		Induced		Total
		(2008-2043)		(2008-2043)		(2008-2043)		(2008-2043)
Economic Benefits & Costs	------ (million $ NPV) ------							
Total Avoided Power Costs	$	42.21	$	-	$	-	$	42.21
Total Solar Benefits		55.12		63.39		31.91		150.42
Total Solar NEM Benefits	**$**	**97.33**	**$**	**63.39**	**$**	**31.91**	**$**	**192.62**
Total Ratemaking Costs	$	48.17	$	1.50	$	36.47	$	86.14
Total Legislative Costs		99.96		60.59		34.94		195.50
Total Solar NEM Costs	**$**	**148.14**	**$**	**62.09**	**$**	**71.41**	**$**	**281.63**
Total Solar Net Benefits	**$**	**(50.81)**	**$**	**1.30**	**$**	**(39.50)**	**$**	**(89.01)**

The AAE's claim that an update of this study would lead to differing results, given the fact that the tax incentives associated with solar development have expired, are also without merit. Consider that, while legislative tax incentives accounted for approximately 69.4 percent of total costs in Staff's Cost Benefit Report, these tax incentives also accounted for an exceptionally large part of the initial economic benefit seen by solar installation in the State. State tax incentives are a transfer payment, with non-participating State taxpayers financially assisting participating net metered installations. A CBA, if balanced in examining both costs and benefits, accounts for the positive economic impacts associated with solar activity in the form of jobs associated with installation activities, and also accounts for the costs associated with these benefits, which in Staff's Cost Benefit Report included the tax incentive. Removing the impact of these tax incentives, therefore, results in little relative change in the net benefits of the Commission's net metering policies since it removes amounts associated with the costs and benefits of the tax incentive. The solar advocates would have the Commission remove the costs of the legislation in considering this analysis while ignoring the large benefits that the legislation created in generating solar-related jobs and output. The net benefits from Staff's Cost Benefit Report, removing the impact of the previous tax incentives, are approximately ($43.93) million on an NPV basis – that is, the removal of the tax incentives still results in a net cost to Louisiana ratepayers.

Table 2: Staff Cost Benefit Report Findings, Excluding Tax Benefits

Economic Benefits & Costs	Economic Impacts Direct (2008-2043)	Indirect (2008-2043)	Induced (2008-2043)	Total (2008-2043)
	(million $ NPV)			
Avoided Generation Energy	$ 33.89	$ -	$ -	$ 33.89
Avoided Generation Capacity	8.20	-	-	8.20
Avoided T&D	0.12	-	-	0.12
Total Avoided Power Cost Benefits	**$ 42.21**	**$ -**	**$ -**	**$ 42.21**
Unrecovered Interconnection Costs	$ 1.54	$ -	$ -	$ 1.54
NEM Administrative Costs	6.46	-	-	6.46
Rate Impacts: NEM Payments	6.57	1.06	4.42	12.04
Rate Impacts: Lost Revenues	33.60	0.44	32.05	66.09
Total Ratemaking Costs	**$ 48.17**	**$ 1.50**	**$ 36.47**	**$ 86.14**
Total Solar Net Benefits	**$ (5.97)**	**$ (1.50)**	**$ (36.47)**	**$ (43.93)**

Second, the solar advocates are incorrect in stating that the Commission needs to "approve" a CBA, or Staff's Cost-Benefit Report, before adopting an updated Rule in this proceeding. The Staff Cost-Benefit Report was prepared, finalized and filed with the Commission pursuant to, and consistent with, its March 2014 B&E meeting directives. There was no express procedural requirement identified at that time, nor any other subsequent time period, requiring the Commission "approve" any report arising from these directives. Further, the Commission is not obligated to "approve" all analyses, reports, memorandum, or other materials prepared by Staff for the Commission's assistance. Furthermore, from an evidentiary perspective, the Commission typically evaluates all record evidence and applies a weight to that evidence based upon its merits. The Commission opened this proceeding as a broad investigative process to collect and evaluate information relative to its current and prospective DER and net metering policies. The Commission, in its fact finding role, need not approve each and every piece of evidence submitted during this process nor any other rulemaking process. The process utilized by the Commission has provided all interested parties with numerous opportunities to express their views on all of the issues in this proceeding. Multiple rounds of comments on the Staff's drafts were sought and submitted by a variety of stakeholders in this process. As the report reveals, the Staff has read, carefully considered and in fact adopted many of the recommendations made by interested parties.

Lastly, Staff disagrees with the solar advocates' assertion that the proposed Staff Rule will drive up retail rates and will not be in the public interest. In fact, adoption of the Staff Proposal will result in the opposite. The Commission's past practices have resulted in a considerable cross-subsidization from non-solar adopting customers to those installing rooftop solar. A good part of this cross subsidy will be eliminated if the Proposed Staff Rule is adopted. Further, the presence of this cross-subsidy is in direct contradiction with the LREDA. Removing a large cross-subsidy, and bringing the Commission's Rule into compliance with state statutes, can result in no other outcome, by definition, than being in the public interest.

2.2.2. Two-Channel Billing

a. **Parties Position:** The proposed Rule changes the manner in which behind-the-meter electricity generation and retail electricity sales will be "netted." Under the Commission's current Rule, behind the meter generation and retail sales are netted each month, on an energy flow (kWh) basis. The kWh difference (self-generation versus on-site usage) is then multiplied by a retail sales rate and credited or debited to the customers' account depending upon the nature of the electricity flows.

Staff proposes to change this "netting" methodology to one that requires utilities to value behind the grid generation and retail sales separately before taking the difference to arrive at a monthly "net" amount. In other words, onsite generation (in kWh terms) in any given month will be tabulated and multiplied by a "reimbursement rate" (avoided cost) whereas total on-site usage will be tabulated and multiplied by the utility's tariffed (regulated) volumetric rate. The difference between these two revenue streams will be the amount billed or credited to a NEM customer's bill. This process, in Louisiana, has colloquially been referred to as "two-channel" billing but, in other states where the process is utilized, the process is commonly referred to as "net billing." This type of net metering billing process has been used for the past three years, for instance, in neighboring Mississippi.

Parties' positions on the two-channel billing proposal can be separated into two opposing camps with jurisdictional utilities, on the one hand, supporting the two-channel, or net billing proposal, and supporters of solar, on the other hand, opposing the Staff net billing proposal. For instance, jurisdictional utilities noted that the two-channel billing approach is comparable to the "netting" approach currently being utilized by the

Commission under its temporary Rule adopted in November, 2016. The jurisdictional utilities correctly note that the proposed Staff Rule simply makes this two channel or net billing approach permanent.

SWEPCO argues that the use of a two-channel approach is important in order to reduce potential cross-subsidization issues. SWEPCO notes that utilities develop infrastructure to serve existing and forecast customers and loads. Rates, in turn, are developed in a fashion that allows utilities the opportunity to earn a return on their prudently-incurred capital investments and reasonable expenses (i.e., rates are designed to reflect a utility's cost of service). When a customer installs behind-the-meter generation, that customer stops contributing to a utility's cost of service, and that unrecovered cost responsibility shifts to other ratepayers. In other words, under the Commission's prior net metering Rule, non-net metered customers were required to subsidize net metering customers since net metering customers stopped making financial contributions to a utility's plant investments once their own behind-the-meter systems were in place and generating electricity.

SWEPCO notes that the current method of "netting" usage and generation aggravates this cross-subsidization. SWEPCO notes that, during the year 2017, it sent 2,210 bills to net metered customers where the total KWh for billing purposes was zero. SWEPCO states that, in its opinion, this was not the intended purpose of the Commission's net metering Rule, and that it is hopeful that any modification to the Commission's Rule focus on removing these cross subsidizations from occurring.[94]

Solar advocates do not support Staff's two-channel billing proposal. AAE argues that the two-channel billing approach is inconsistent with the LREDA since the statute states, in its "legislative findings," that net metering can serve as "... a means of promoting the wise use of Louisiana's natural resources and to stimulate economic development and job creation in the State." AAE argues that the Staff proposal will result in the inverse but does not provide any empirical or other evidence that quantifies how DER generation will be reduced by using two channel billing.[95]

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[94] Comments on Behalf of Southwestern Electric Power Company, at 2.
[95] Comments on Behalf of the Alliance for Affordable Energy, at 5.

The Sierra Club similarly argues that the Staff two channel billing proposal is inconsistent with the LREDA since the statute defines net metering as "...measuring the difference between electricity supplied by an electric utility and the electricity generation by a net-metering customer and fed back to the electric utility over the applicable billing period."[96] Sierra Club contends that the proposed two-channel billing process is inconsistent with the statutory definition which, purportedly, is explicit in "valuing" electricity in energy (kWh) terms, not dollar amounts.[97] Sierra Club argues that the two channel approach, by contrast, offsets the financial differences (the "payments" for generation and the "charges" for electricity service) as opposed to the energy (kWh) flows (i.e., the kWhs from generation less the kWhs from usage).

PosiGen makes a broader public policy argument, noting that 38 states, Washington D.C, and four U.S. territories offer retail "net metering;" where, supposedly, "net metering" is intended to reflect a process that nets energy (kWh) flows rather than financial differences. PosiGen also notes that two additional states, Idaho and Texas, also offer voluntary "net metering" programs.[98] In total, according to PosiGen, 80 percent of state energy regulatory authorities require retail net metering, putting Louisiana in the bottom 20 percent nationally.[99] PosiGen therefore requests that the Commission "at a minimum" reinstate full retail net metering.[100]

GSREIA suggests that Staff's two channel billing approach is comparable with the process by which qualifying facilities ("QFs") were reimbursed under PURPA. GSREIA believes this similarity is inappropriate since "(s)olar (distributed energy resources) are not the same resource as central generation or large power plants traditionally used to supply grid electricity," and that it is therefore inappropriate to apply a framework similar to that utilized by PURPA for solar distributed generation."[101] GSREIA argues that most solar facilities do not require large upfront capital investments, and are primarily designed to serve the needs of the immediate

[96] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 3.
[97] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 3.
[98] Comments of PosiGen of Louisiana, LLC on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 9.
[99] Comments of PosiGen of Louisiana, LLC on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 10.
[100] Comments of PosiGen of Louisiana, LLC on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 10.
[101] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 6 and 7.

facility.[102] GSREIA claims that, in Louisiana, only 20 to 30 percent of energy produced by net metered solar facilities are generally exported to the grid.[103] Lastly, GSREIA argues that developing a "PURPA-like" Rule is inappropriate since solar-based, distributed generation only travels a short distance before interacting with the utility's electric grid, unlike "larger" QF facilities which presumably move power over considerably long distance.[104]

b. **Staff Response:** In summary, parties opposed to Staff's two channel billing proposals make the following arguments:

- Two channel billing is inconsistent with the LREDA.
- Two channel billing will discourage future Louisiana DER capacity development.
- DER should not be subjected to a reimbursement approach that is comparable to other customer-owned generation resources such as QFs under PURPA.

Staff disagrees with each of these arguments since all fail to address, or appreciate, the important negative ratepayer impacts associated with the Commission's prior method of reimbursing DER installations.

First, consider that the Commission's prior net metering valuation methodology effectively forced one group of ratepayers (those without onsite DER) to cross subsidize customers with DER installations. This cross subsidy arises since ratepayers without DER installations are forced pay for: (a) the unrecovered costs of metering, measuring and monitoring DER installations; (b) an electricity generation commodity that is valued at full retail rates and not the opportunity cost of generating that electricity; and (c) the cost of maintaining the capacity and infrastructure associated with the utility infrastructure that is relied upon by DER installations for backup electricity and for retail electricity when solar energy is not sufficient to meet a DER customer's full retail electricity usage requirement. In fact, the Staff Cost-Benefit Report estimates, based on active installations at the

[102] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 6 and 7.
[103] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 6.
[104] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 6.

end of 2013 that most Louisiana ratepayers were providing over $2.3 million in ratemaking-related subsidies annually to the handful of DER installations located throughout the state, and within the LPSC's jurisdiction.[105]

Second, Staff strongly disagrees with the assertions made by the Sierra Club, GSREIA, and other solar advocates that two channel billing, or net billing, is in any way inconsistent with the LREDA. If anything, the Commission's prior net metering practices, which result in large cross subsidies from one class of ratepayers to another, is arguably inconsistent with the LREDA. This cross subsidy problem, however, can be largely remedied through the use of a two channel approach outlined in the Staff Proposed Rule. The two-channel approach will eliminate the over-payment of on-site, distributed generation since one flow of electricity (that generated behind the meter), will be valued at avoided cost while a second flow (that sold to the DER customer) will be valued at full retail rates. The financial difference in these two streams of electricity will represent the "net" payment received by a DER installation.

Sierra Club, among others, also argues that two channel billing is inconsistent with how "net energy metering" is explicitly defined in the LREDA. The statute defines net energy metering as "measuring the difference between electricity supplied by an electric utility and the electricity generated by a net energy metering customer and sold back to the electric utility over the applicable billing period." Staff disagrees that its Proposed Rule is inconsistent with this statutory requirement since the two-channel approach will not eliminate the "netting process" and continues to value both generation and retail sales made by DER customers in making monthly "net" reimbursement calculations.

The primary difference between a two-channel approach and the Commission's prior net metering practice is that the two channel approach recognizes that a kWh of <u>electricity generation</u> being provided by a DER installation does not have the same <u>value</u> as a kWh of <u>retail electricity service</u> being provided by the utility to the DER end-user. The electricity being provided by a DER installation, to a host electric utility, is an unbundled energy commodity only. This commodity does not include any direct transmission, distribution or any other

[105] David E. Dismukes. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers.* Final Report Prepared on the Behalf of the Louisiana Public Service Commission. September 23, at 160.

customer service characteristics. Thus, DER generation should be reimbursed based upon its direct attributes which are energy commodity-related only. This DER-based commodity energy stands in stark contrast to the retail electricity service provided by a utility which is a "bundled" service that includes not only commodity electricity, but transmission, distribution and customer service characteristics, the value of which is included in a utility's cost of service, the primary basis for a utility's retail electricity service rates. Further, there is nothing, on either an explicit or implicit basis, in the LDREDA that requires these two flows of electricity (generation, retail purchases) to be valued in a similar fashion.

The solar advocates' arguments merely conflate the methods by which DER is measured versus how that DER generation is valued. While the LREDA defines how DER generation is measured, it says nothing about how DER generation is valued. In fact, the LREDA is silent on the issue of whether DER generation should be valued at full retail utility rates or, alternatively, some other rate reflective of avoided cost or some other value. It is for good reason that the LREDA is silent on this DER valuation issue. Contrary to Sierra Club's incorrect assertion, it is a well-established and recognized fact that the Commission's ratemaking authority and responsibilities inure through the Louisiana Constitution, not through statute. It is simply not the place of the Louisiana Legislature to dictate to the Commission how rates are set for any utility service.

The Louisiana Public Service Commission is a constitutionally-created body vested with plenary authority over the rates and services of Louisiana utilities.[106] Article IV § 21(B) of the 1974 Louisiana Constitution delegates to the Public Service Commission the exclusive and plenary power to regulate all common carriers and public utilities. The Supreme Court of Louisiana has found that the "Commission's power in this regard is as complete in every respect as the regulatory power that would have been vested in the legislature in the absence of Article IV § 21(B)."[107] Therefore, the legislature's acts or omissions cannot subtract from the Commission's exclusive, plenary power to regulate all common carriers and public utilities.[108]

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[106] La. Const. Art. IV, § 21

[107] Bowie v. Louisiana Public Service Com'n, 627 So. 2d 164 (La. 1993).

[108] *Cajun Electric Power Cooperative, Inc., v. LPSC,* 544 So. 2d 362 (La.), *cert. denied* 493 U.S. 991, 110 S. Ct. 538, 107 L. Ed. 2d 536 (1989); *Cajun Electric Power Cooperative, Inc., v. LPSC,* 532 So. 2d 1372, 1380, 1381 (La.1988) (on original hearing) (Dennis, J. dissenting) (Calogero, J. dissenting); *South Central Bell Telephone Co. v. LPSC,* 412 So. 2d 1069, 1070 (La.1982); *Central Louisiana Electric Co. v. LPSC,* 373 So. 2d 123, 128 (La.1979); *Louisiana Consumers' League Inc. v. LPSC,* 351 So. 2d 128, 131 (La.1977).

Therefore, Sierra Club's statements are factually incorrect: Staff's two channel billing proposal is not inconsistent with the LREDA since the LREDA is silent on how the financial differences, and rates used to develop those financial differences, are defined. Further, the Legislature has no authority to determine such values and, in fact, the LREDA explicitly recognizes the Commission's authority on these issues by explicitly stating that "nothing in this [Act] shall derogate from the commission's constitutional authority"[109] with regard to pricing, valuating DER service, or any other DER rulemaking terms and conditions.

Thus, the two channel provisions included in Staff's proposed Rule, if anything, are more, not less consistent with the LREDA than the Commission's prior net metering methods. The prior Commission methodology, for instance, effectively cross-subsidizes DER installations by reimbursing DER generation at a rate that is higher and inconsistent with those DER installations' respective costs. Under the Commission's prior methodology, ratepayers were required to reimburse DER installations for these excessive generation costs through their retail rates. This subsidization is explicitly inconsistent with the LREDA which states that nothing in the law should be used to "subsidize [any DER] activities authorized under this Chapter." Thus, to the extent the Commission is concerned about LREDA compliance, it should permanently move its DER reimbursement process to one based on two channel billing rather than its prior methodologies that allowed for this cross-subsidization.

Thirdly, Sierra Club and other solar interests also assert that Staff's two channel billing proposal will effectively "end" all DER development in the state. This statement is false and inconsistent with recent Louisiana empirical trends. DER installations, particularly behind-the-meter solar installations, have been stimulated by considerable tax incentives provided by both the Louisiana Legislature and federal investment tax credits ("ITCs"). The role of tax incentives on Louisiana DER development has very strong empirical support whereas the solar advocates' assertion that DER installations are a function of the Commission's DER policies is unsupported by any empirical evidence offered by these intervenors.

[109] La R.S. 50: 3063(c).

A simple review of the DER installation trends for the LPSC jurisdictional utilities shows that annual DER installation levels have been strongly influenced by state and federal tax policies, not the Commission's net metering policies. Consider that the LPSC first adopted a very generous net metering Rule back in November, 2003.[110] This was approved approximately six years prior to the Louisiana solar tax credits that provided an effective 50 percent tax credit on solar installations that are less than $25,000 in total cost and no more than 6 kW in total capacity.[111] Figure 21 shows that during this four year period, virtually no DER installations were added in the state despite the fact that the valuation methods used by the Commission to reimburse these installations during that time period was highly subsidized. Installations did not begin to accelerate until 2008, the year in which tax subsidies at both the federal and state level were offered.

[110] *Net Energy Metering Rule-making;* Docket No. R-27558, Order dated November 9, 2005.
[111] LSA-R.S. 47:6030.

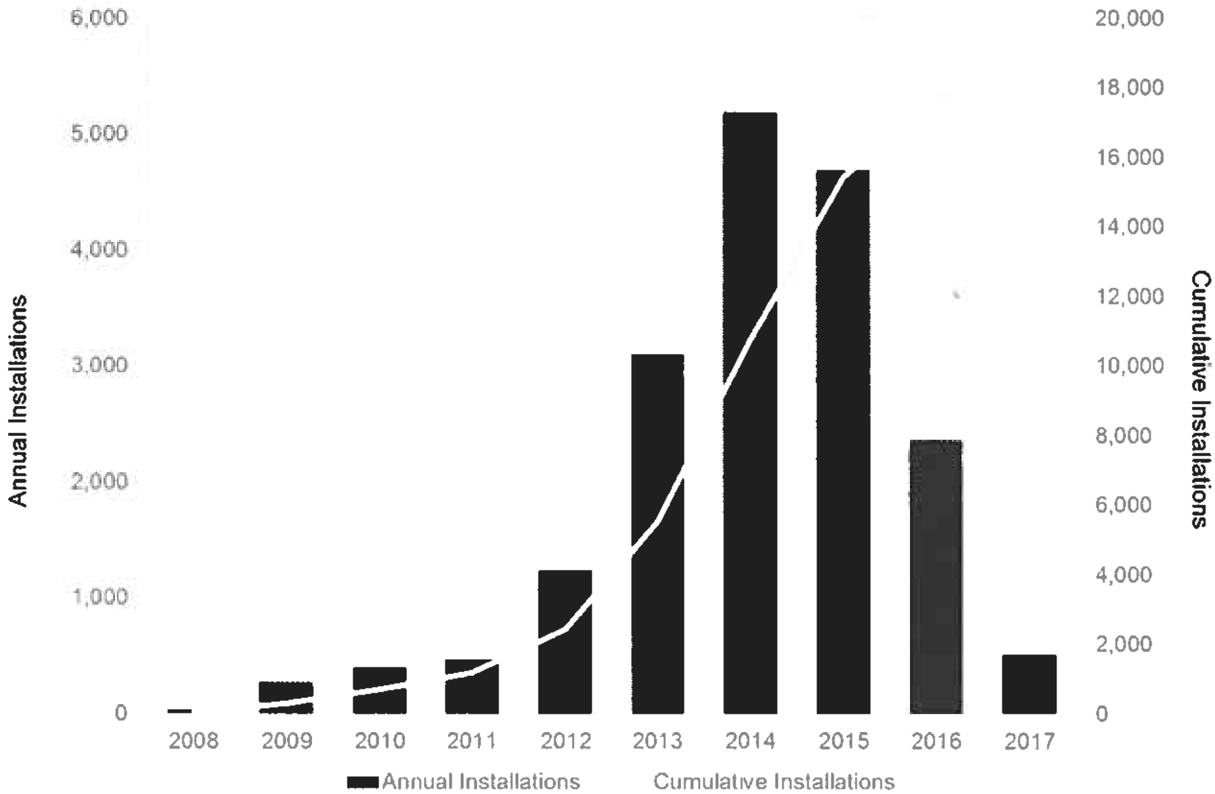

Figure 21: Louisiana Solar Net Metering Installations
Source: Dismukes, David (2015), *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers;* and LPSC Net Metering Annual Reports.

Further, Staff estimates that during the time period of 2008 through 2014, Louisiana DER installations received nearly $133 million in total direct state tax incentives versus $1.66 million in net metering subsidies (calculated as the difference between the estimated avoided cost during this time period and the full retail rate). In other words, from a financial perspective, Louisiana DER installations received more than 80 times as much in direct installation subsidies as they did in net metering reimbursement subsidies. No assertion can be offered suggesting these historic net metering subsidies, in any way, motivated the significant DER development witnessed during this time period, nor can it be claimed that a movement to two channel billing, which will still provide DER generation with financial payments, will substantially reduce the incentives for developing behind-the-meter generation.

Lastly, GSREIA asserts that a PURPA-type approach to distribution-level distributed generation is inappropriate since: (a) DER installations are not comparable to wholesale generation; (b) DER installations do not require large amounts of upfront capital; and (c) DER installations are designed to serve local onsite loads,

unlike those of qualifying facilities ("QFs") that, purportedly, put relatively more electricity to the grid than their smaller scale counterpart. Respectfully, GSREIA is factually incorrect on all points.

In addressing GSREIA's cost issue first, all DER applications installed since 2008 in Louisiana have been restricted to renewable resources, primarily solar PV applications. GSREIA is partially correct in noting that a typical Louisiana residential solar installation investment is "small." Nationally, those costs average $2,800 per kilowatt ("kW") installed, or approximately $16,800 for a 6 kW solar installation.[112] This stands in stark contrast to the total cost of a large industrial cogeneration 250 MW installation that may cost as much as $275 million. However, on a relative basis, the cost for the solar system, on a cost per kW basis, is considerably higher.

For instance, a residential solar installation investment, can be as high as $3,500 per kW in Louisiana[113] relative to a new cogeneration investment that is around $1,100 per kW on a standardized basis. Further, on a levelized basis, a solar DER installation is considerably more capital intensive than a cogeneration facility that has to contend with natural gas fuel and operations and maintenance ("O&M") expenses.

Regardless, the cost argument made by GSREIA is misplaced since PURPA was never intended to address either total or relative "costs," but instead, to address a variety of market barriers to non-utility generation. It has been asserted, in fact, that the U.S. Supreme Court recognized that the intent of PURPA, much like many state DER policies, was, among other things, to encourage the development of renewable power generation as an alternative to using fossil fuels.[114] It is, in fact, the market barriers to non-utility generation that both PURPA and net metering policies were intended to address through:

- Requiring utilities to interconnect QFs into their respective transmission/distribution grids.
- Requiring utilities to provide emergency, standby and backup electricity to QFs in the event of an unplanned outage.
- Requiring utilities to purchase excess electricity from QFs at the utility's, not the QF's, marginal (avoided) cost.

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[112] Fu, Ran, et. al. (September 2017), *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017*, National Renewable Energy Laboratory, at vi.

[113] *See*, News Feed, *How Much Does a 15,000 Watt (15kW) Solar System Cost*, energysage, available online at: https://news.energysage.com/15-kw-solar-system-cost/; the average cost of solar in the U.S. as of January 2018 was $3.26 per watt, or $3,260 per kW.

[114] *PURPA-qualifying capacity increases, but it's still a small portion of added renewables* (August 16, 2018), Today in Energy, Energy Information Administration; and *FERC v. Mississippi*, 456 U.S. 742, 745-46 (1982).

PURPA was enacted in 1978. The full embrace and impact of PURPA, however, did not begin in earnest until the early 1980s after a U.S. Supreme Court decision upholding the legislation and its provisions.[115] Interestingly, it was during this same time period (the early 1980s) that many states began to adopt net metering policies as a distribution level counterpart to PURPA. In fact, many contemporary research papers examining NEM policies recognize this NEM/PURPA nexus, in direct contradiction to GSREIA's assertions.[116]

Consider further that, during the same early PURPA implementation period:

- The Idaho Public Service Commission is cited as one of the earlier states, in 1980, adopting NEM policies requiring generation interconnection and buy-back for all distribution level resources below 100 kW.
- The Arizona Corporation Commission and the Massachusetts Department of Public Utilities are also cited as early adopters, creating NEM-based programs for small-scale generators under 100 and 30 kW, respectively, in 1981 and 1982.
- In 1983, the Minnesota legislature enacted Statute 216B.164, allowing net metering for all qualifying facilities under 40 kW on a statewide basis. The Minnesota legislation is often cited as the first enactment of a state-wide, rather than utility-specific, NEM policy.

Lastly, GSREIA makes the argument that PURPA-style principles should not be incorporated into the Staff proposed Rule since DER installations differ considerably from QFs since DER installations, presumably unlike QFs, put considerably little electricity to the grid. Once again, GSREIA is factually incorrect.

Figure 22 shows the historic generation from Louisiana QFs over the past five years. The figure shows that two-thirds or more of the electricity generated at these industrial QFs remained within the fence-line and was not sold back to their respective host utility. This is not dissimilar to the figures referenced by GSREIA that typical solar DER facility only exports 20 to 30 percent of generated electricity, i.e. 70 to 80 percent of all generation is used behind the meter.[117]

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115 *FERC v. Mississippi*, 456 U.S. 742, 745-46 (1982).

116 See: Revesz, R.L. and B. Unel. 2017. Managing the future of the electricity grid: distributed generation and net metering. Harvard Environmental Law Review, Vol 41; Saarman Gonzále, G.S. 2017 Evolving jurisdiction under the federal power act: promoting clean energy policy. UCLA Law Review. 63 UCLA L. Rev. 1422 (2016); Reiter, H.L. and W. Greene. 2016. The case for reforming net metering compensation: why regulators and courts should reject the public policy and antitrust arguments for preserving the status quo. Energy Law Journal, 37:373. November 11; and Hickey, J. and A. Ryou. 2016. The distributed generation (DG) phenomena. Journal of International Buisiness and Law. Vol. 15: Iss. 2, Article 3.

117 Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 6.

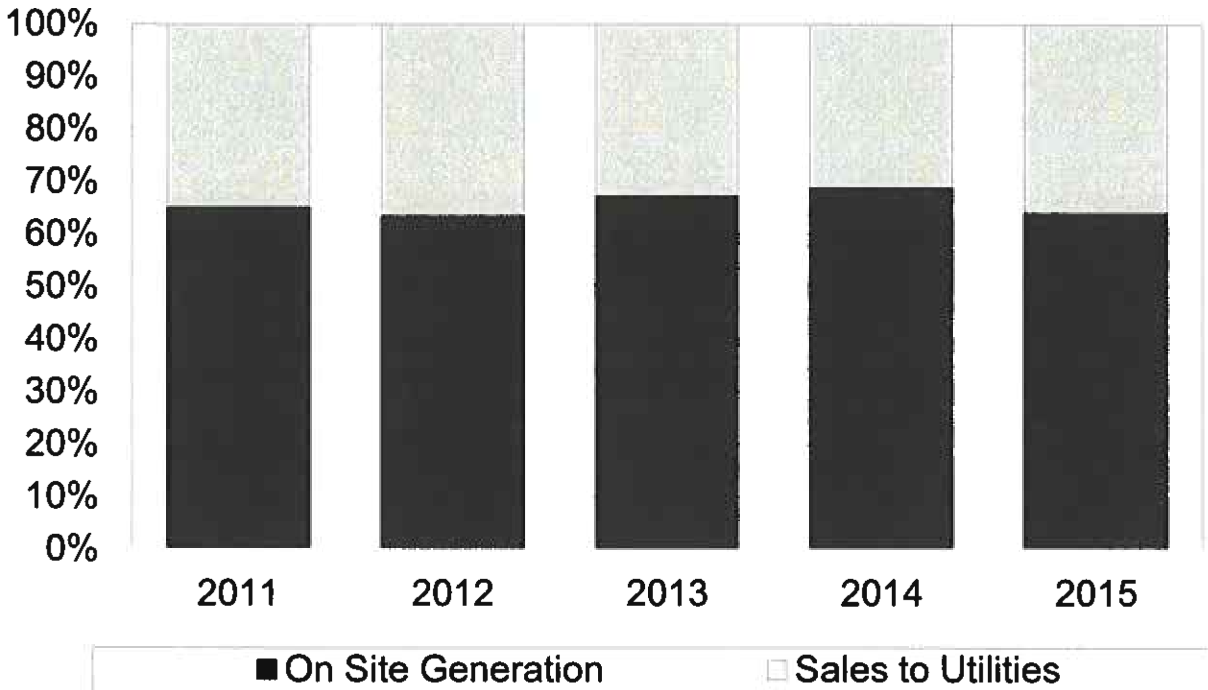

Figure 22: Louisiana On-Site QF Generation and Utility Sales Shares
Source: Energy Information Administration.

2.2.3. Avoided Cost

a. **Parties Position:** Staff's proposed Rule will "value" behind-the-meter generation at avoided cost, not full retail rates. This proposal differs from the originally-adopted Commission Rule but is entirely consistent with the current temporary Rule. Furthermore, this proposed Rule will (1) serve to eliminate a good part of the cross subsidies that have existed between the general class of ratepayers and those adopting solar and (2) make the Commission's temporary Rule permanent and bring that Rule into compliance with the LREDA.

The jurisdictional utilities support the Staff proposal to value behind-the-meter generation at avoided costs although there appears to be some question among the utilities on just exactly how avoided costs will be determined. SWEPCO, for instance, expresses an interest in utilizing its Purchase Power Service ("PPS") tariff as a means of reimbursing behind the meter solar installations for the on-site generated electricity. SWEPCO asserts that the use of the PPS tariff would reduce administrative costs and provide reimbursement consistency

across differing generation types.[118] SWEPCO also requests that the Commission provide limits on the number of "key factors" that would be utilized in establishing utility-specific avoided costs on a forward going basis.[119]

Both Entergy and SWEPCO requested that the proposed avoided cost language be modified to allow utilities that operate in organized markets, such as the Southwest Power Pool ("SPP") or Mid-Continent Independent System Operator ("MISO") day-ahead or capacity markets, to utilize information reported in these markets for avoided energy and capacity prices compliance purposes. Entergy, for instance, requests that the proposed avoided cost language be modified to allow utilities to utilize reported locational marginal prices ("LMPs") which, themselves, could be modified to reflect the operating characteristics of the distributed generation facility.[120] SWEPCO had similar comments to this regard, expressing support for the use of a time-variant market price to appropriately incent distributed generation at times when the generation is most needed.[121]

The comments provided by solar advocates were generally not supportive of the Staff proposal to make permanent the Commission's current, temporary provision that reimburses behind-the-meter generation at avoided cost rather than full retail rate. Many solar advocates argued that the proposed Rule does nothing to enhance avoided cost pricing transparency for average customers attempting to make a behind-the-meter generation installation decision. Other solar advocates argue that the avoided cost provisions of the proposed Rule is ambiguous and should include additional detail on how avoided costs should be specifically calculated, going so far, in some comments, as suggesting that the Staff should have developed its own set of explicit, utility-specific avoided cost reimbursement rates in the proposed Rule.

PosiGen, for instance, claims that the avoided cost provisions of the proposed Rule is "extremely confusing"[122] and the Sierra Club claims that "the exact parameters of [the avoided cost] requirement are so unclear as to prohibit effective public input or notice to solar businesses and potential solar customers."[123] The

[118] Comments on Behalf of Southwestern Electric Power Company, at 5.
[119] Comments on Behalf of Southwestern Electric Power Company, at 7.
[120] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 3 and 4.
[121] Comments on Behalf of Southwestern Electric Power Company, at 5 and 6.
[122] Comments of PosiGen of Louisiana, LLC on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 10.
[123] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 4.

Sierra Club also claimed that the proposed Rule provide "virtually no guidance" as to what would constitute an innovative alternative rate acceptable to the Commission, which would lead most utilities into utilizing avoided cost rates based on existing rates used for purchase power purposes.[124] The Sierra Club, furthermore, argues that avoided costs, as they are used today for other generation reimbursement purposes, are "difficult to locate – let alone comprehend," making it "nearly impossible" for the average customer to effectively make decisions with regards to distributed generation systems.[125]

GSREIA argues that Commission should adopt a uniform statewide "solar avoided cost" rate that would, presumably, apply to all jurisdictional utilities (coops and IOUs) and include additional financial payments to reflect the benefits of distributed generation in addition to the traditional benefit of avoided utility generation.[126] AAE notes that current avoided costs vary by a wide range, between 2.45 cents per kWh to 4.6 cents per kWh, and that a uniform rate would be in the best interest of current and prospective behind-the-meter generation installations.[127] AAE prefers a standardized avoided cost rate that does not vary across utilities, or over time, and takes into account the additional benefits provided by solar energy, in particular.[128]

b. **Staff Response:** Parties' comments on the avoided cost issue can be separated into two positions. The first set of positions is articulated by the utilities, which express an interest in using market-based proxies, or existing tariffs, for avoided cost purposes. The second set of positions, articulated by the solar advocates, questions the use of an avoided cost measure for DER generation reimbursement instead of using the full retail rate. These solar advocates also express concerns about perceived ambiguities in the proposed Rule's definition of avoided cost and the transparency of these avoided costs to those interested in DER installations.

The central controversy in setting the behind-the-meter generation reimbursement rate rests on whether a market-based proxy should be used or some other form of administratively-determined rate, on a level comparable to current retail rates, should be used. Utilities express a preference for the use of a market-based avoided cost

[124] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 4.
[125] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 4.
[126] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 10 and 11.
[127] Comments on Behalf of the Alliance for Affordable Energy, at 6.
[128] Comments on Behalf of the Alliance for Affordable Energy, at 6.

measure whereas solar advocates express a very strong belief that a rate comparable to the retail rate of electricity should be used. This issue is likely the single most important issue associated with this proposed Rule, so it will be addressed in detail.

Avoided cost is primarily an electric industry-based term used to define what is known in economic theory as the marginal cost of providing electricity, where the marginal cost of electricity itself, is defined as the cost of providing the next incremental level of generation any a given point in time, such as on an hourly or monthly basis. The absolute value of this marginal cost of generation is often low since it only reflects fuel costs and, since the marginal generator is usually defined by a high-efficiency natural gas unit, the avoided cost can be relatively low. Further, avoided costs are generation-related only, they do not include the costs of other aspects of utility service such as transmission, distribution and other retail functions. Avoided costs simply represent the commodity cost of electricity.

A retail rate, on the other hand, is based upon a utility's full cost of service and can be thought of, in economic theory terms, as the "average cost" of providing utility service since cost-of-service rates effectively take a utility's total cost of service and divide those costs by billing units (e.g., kWhs) to arrive at a "unit cost" or "rate." The full cost of service used to develop retail rates, in turn, is based upon the cost of providing vertically integrated utility service that includes generation, transmission, distribution, and other customer services, not just generation alone. Thus, retail sales based rates will often be higher than a utility avoided costs, so it should come as no surprise that any non-utility generator will find it in its best economic interest to attain a reimbursement rate that tends to reflect a higher, not lower financial value.

Solar advocates in this proceeding argue that the Commission should set behind-the-meter solar generation reimbursement rates equivalent to the full retail service rate. For instance, AAE notes that net metering is "an appropriate policy that fairly credits customers who generate their own electricity, and acknowledges the benefits these installations provide to the grid."[129] Among the primary reasons AAE, and other solar advocates, support the use of a retail rate are that: (a) it results in a more generous reimbursement for solar installations (relative to

[129] Comments on Behalf of the Alliance for Affordable Energy, at 8.

avoided costs); and (b) it is consistent with how these DER installations have been reimbursed in the past, in Louisiana as well as many other states.

However, the use of retail rates for net metering reimbursement purposes is a legacy artifact of the 1980s and 1990s when DER installations were exceptionally limited, and the administrative cost of developing distribution level avoided costs were considered too high and unnecessary. Retail rates, instead, were used given the administrative ease, and the recognition that pricing at this level, did, in fact, lead to a subsidy that was deemed in the public interest to promote technologies that were exceptionally costly relative to other market alternatives.

The use of retail rates for DER reimbursement purposes went unchallenged for close to two decades until, in 2005, retail electricity prices began to soar and state RPS implementation passed the point of being moderately progressive to exceptionally aggressive. Simply put, the cost of continuing to reimburse large amounts of renewable energy-based DER, at high retail electricity rates, was simply unsustainable and, over the past decade, has forced many states to reconsider their net metering reimbursement processes.

The use of retail rates for DER reimbursement is inconsistent with good regulatory policy, results in market inefficiencies, and, most importantly, represents nothing more than a subsidy that transfers wealth away from ratepayers without DER installations to those with DER installations, an outcome inconsistent with the LREDA. Retail electricity rates have nothing to do with the cost of DER generation, nor do these retail rates reflect the opportunity cost of generation based upon any market-based measure, such as a day-ahead market or any form of LMP pricing.

This does not suggest that the Commission cannot set a DER reimbursement rate at a generous level that is somewhat above avoided cost or even comparable, in absolute value, to retail rates, but Louisiana DER policy needs to decouple this retail rate/DER reimbursement relationship once and for all, hence the rationale for Staff's avoided cost reimbursement proposal. Solar advocates unnecessarily conflated the issue of offering a "generous" DER reimbursement rate with the use of retail electricity rates which leads to an unnecessary amount of angst in setting net metering policy and has likely prevented any consensus from being able to be enjoyed on this subject.

Staff's proposed Rule attempts to bridge this gap between the two methods of valuing behind-the-meter generation. Section 6.2.1.1 of the proposed Rule identifies a wide range of factors that should be considered in developing a reimbursement rate for DER generation. The clear interpretation of this Rule is that measures commonly used to represent avoided costs (e.g., utility marginal generation costs, regional market clearing prices, day ahead or LMP market prices, and simulated multi-area dispatch modeling results) will set a floor, not a ceiling on the per unit value at which DER generation is reimbursed. Solar advocates paint a picture of gloom and doom that if the Staff Rule is adopted, a relatively low valued market based avoided cost will be the only factor used to set DER reimbursement rates. This is clearly not the case and mischaracterizes Staff' proposed Rule.

Jurisdictional utilities, SWEPCO and Entergy in particular, raise a number of important issues regarding how future avoided costs, and overall DER reimbursement rates, will be determined. First and foremost, Staff agrees with both SWEPCO and Entergy that, to the extent existing organized markets, such as the MISO or SPP day ahead or capacity markets, can be used for price discovery in the determination of an appropriate market-based avoided costs, such measures should be utilized. In fact, Section 6.2.1.1 explicitly states that "avoided costs may be determined by local marginal prices." However, it will be up to utilities to make these proposals, on an individual basis, and to provide the justification to the Commission for the use of this market information in their respective tariff filings.

Staff also agrees with the Sierra Club that, historically, the transparency around the avoided cost rates used to reimburse non-utility generation has been somewhat opaque.[130] However, these transparency arguments were likely more relevant in years prior to the development of RTOs rather than today. Regardless, Staff agrees with Posigen that more needs to be done to make this process transparent. This does not mean, however, that market-based measures cannot be used. Staff notes that many market-based measures for power generation costs are readily accessible and publicly available and can be utilized in developing market-based avoided cost measures for purposes of this proposed Rule.

[130] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 4.

As previously mentioned, SWEPCO's comments also include a suggestion that its existing PPS tariff could be utilized for avoided cost purposes under this proposed Rule. Staff is not ruling out that the avoided cost measures used in SWEPCO's PPS tariff could be utilized as a starting point for the avoided cost defined in this proposed Rule. However, the proposed Rule clearly envisions that the consideration of a wide range of additional factors will be examined in setting DER reimbursement rates: avoided (generation) costs are just one component of these reimbursement rates and, as noted earlier, will set the floor not the cap for reimbursing DER generation put to the distribution grid.

The Staff proposed Rule requires utilities, in setting overall DER reimbursement rates, to consider a wide range of additional factors associated with DER benefits that may lead to utility (and ratepayer) benefits. These "additional factors" lead to the second line of discussion in parties' comments on the avoided cost topic, particularly the comments of the solar advocates that raise questions about the proposed Rule's ambiguity regarding how these "additional factors" will be defined and utilized in setting avoided cost rates for DER tariff purposes. Staff's intent on this subject clearly needs additional clarification.

First and foremost, utilities will be required under the Staff proposed Rule to make DER tariff filings that will be noticed and set up in a fashion that allows intervention by stakeholder groups. The clear regulatory intent here is that utilities will be required to make a factual presentation that they have considered each of the factors identified in the proposed Rule, quantified their likely value, and, if there is no value or the value is small, utilities will have the burden of proof associated with such results. Utilities will not be allowed to summarily dismiss environmental externalities, localized congestion and other factors that may influence the value of DER generation. Stakeholders, furthermore, will be allowed to critique these estimates much like they would in any other type of ratemaking proceeding. Tariffs will be developed on facts, empirical evidence, and sworn testimony: not comments, hearsay and assertions.

The Sierra Club and other solar advocates request that Staff specifically define a methodology, or, in the case of AAE, define a specific menu of avoided costs that will be used on a uniform basis across the state. Staff will not restrict the Commission, through this rulemaking, into a specific methodology or specific set of variables

or specific statewide values to use in setting avoided cost rates for a variety of reasons. First, rulemakings are for policy and not specifics. The purpose of this rulemaking should be to define the general guidelines and principles for DER interconnection, billing, reimbursement practices and other policy issues. Tariffs are typically proposed and litigated in rate cases or other proceedings, they are not developed in rulemakings.

Second, there are a wide range of individual approaches and methods for estimating the value of these "additional factors" and, contrary to the suggestions of the environmental and solar advocates, there is no general consensus on the "preferred" approach or method. This is particularly true as the analysis moves from the general and conceptual, to the specific. Staff believes it should be the burden of the utilities to develop these methodologies and proposals since it is the utilities, not Staff that have more information about the potential benefits associated with DER on their systems, and at very specific locations on those system, across time.

Third, the methods, variables and data used to estimate a reasonable avoided cost for DER reimbursement purposes are not static inputs but are dynamic in nature. What is important in determining the opportunity cost and value of DER will change across utility, RTO location and time. Setting specifics in a rulemaking of this nature is too restrictive, will result in an inefficient set of administratively-determined rates that, themselves, will need to undergo additional future changes and updates. The purpose of the proposed Staff Rule has been to establish a set of guidelines that will have some general applicability for an extended period of time in order to establish an environment of regulatory certainty for utilities, ratepayers, and DER installations alike.

Lastly, Staff disagrees with the more specific suggestion offered by AAE that this rulemaking should establish a set of statewide avoided cost reimbursement rates that will be applicable across all jurisdictional utilities. While it is possible that the development of a uniform set of tariffs could provide some uniformity and transparency benefits, the costs of establishing a uniform set of DER tariffs could outweigh these potential benefits. Consider that:

- As noted earlier, the purpose of a rulemaking is to establish general policy and guidelines on a particular topic. If a specific set of avoided costs are established via this rulemaking, then the reimbursement rates will need to be updated on a regular basis that will require addition resources, costs and time. This will also increase, not reduce, the regulatory uncertainty associated with DER reimbursement rates.

- The time to develop a statewide set of reimbursement rates would be substantial and one of the goals of this proceeding has been to get a permanent rule in place to reduce the regulatory uncertainty of the Commission's policies on net metering and distributed generation.
- Statewide average rates would lead to economic inefficiencies, which, in turn, would send incorrect signals to the market about the opportunity cost and benefits of DER generation. A uniform DER tariff would likely eliminate any pricing variation and reduce local incentives for DER development.

2.2.4. Grandfather Clause

a. **Parties Position:** Staff's proposed Rule includes a grandfathering provision that allows existing installations, and those DER installations in place prior to the new Rule's adoption, to utilize the provisions of the Commission's prior net metering Rule, and its provision, for a period of five years. Only new installations (post-new Rule adoption) would be immediately subjected to new Rule's terms and conditions. After five years, all behind-the-meter generation would be subjected to the provisions of this proposed Rule.

Solar advocates appear to agree with the grandfathering principle but believe that the proposed five-year period is too short. Jurisdictional utilities are generally silent in their response to the grandfathering issue.

The Sierra Club notes that the LPSC has a "statutory" obligation to set just and reasonable rates for all ratepayers.[131] The Sierra Club notes that the use of grandfathering allows for a fair, stable, and predictable phase-in of any new rate structure for net-metering customers that have undertaken significant investment in renewable generation systems.[132] The Sierra Club argues that failure to grandfather existing customers would be economically unfair to existing customers, and noted that this belief has underlined many other regulatory commissions' decisions modifying net metering policies.[133]

The Sierra Club ultimately argues that the Commission should implement a 20-year grandfathering provision consistent with recent decisions made by the Arizona Corporation Commission and Public Service Commission of Nevada.[134] This position was also supported by AAE, which noted that, in addition to the Public Service Commission of Nevada, the Arkansas Public Service Commission has adopted a 20 year grandfathering provision in its recent changes to its net metering policy, and the Indiana Utility Regulatory Commission adopted

[131] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 10.
[132] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 11.
[133] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 11.
[134] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 13 and 14.

a 30 year grandfathering provision.[135] Finally, while not providing a detailed rationale, GSREIA also recommended a 20 year grandfathering provision.[136]

Jurisdictional utilities were generally silent with regards to the proposed grandfathering provision; at least on an individual utility level. ALEC, the association representing most of the distribution cooperatives in the State, however, did address the grandfathering provision. ALEC reiterates its belief that avoided costs are the appropriate basis for reimbursing distributed generation and that the sooner this process is adopted for all distributed generation, the better.[137] Given this position, ALEC believes that the proposed five year grandfathering period is too long, and that the Commission should consider a more appropriate time frame of only three years.[138] ALEC provides no evidence on why three years is more appropriate than five and appears to simply base its position on policy rather than empirics.

b. **Staff Response:** The purpose of Staff's proposed five year grandfathering clause is to provide an orderly regulatory and market transition from the Commission's prior net metering Rule to Staff's newly proposed DER Rule. Staff chose a five year grandfathering period because this time period was long enough to ensure an orderly transition, and, more importantly, corresponded with the solar industry's commonly quoted four to five year payback periods for solar installations.

However, the solar advocates in this proceeding have taken considerable issue with this grandfathering period, despite the fact that it is consistent with their own literature and marketing materials on how quickly households can achieve payback on their solar installations. Instead, the solar advocates argue for a 20 year grandfathering period which is unreasonable and would render any changes in the Commission's net metering Rule moot and meaningless since the overwhelming majority of the solar installations in service in Louisiana would be eligible for this extremely long and unnecessary grandfathering period.

[135] Comments on Behalf of the Alliance for Affordable Energy, at 2.
[136] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 12.
[137] Comments of the Association of Louisiana Electric Cooperatives, inc., at 4.
[138] Comments of the Association of Louisiana Electric Cooperatives, inc., at 4.

Staff's rationale for tying the grandfathering period to a typical solar payback period is fourfold: (1) there is nothing in the Commission's policies, nor any regulatory Commission's policies, that includes any long term extraordinary pricing guarantees that are not explicitly defined by a utility's tariff or some other special contract provision; (2) Staff's grandfathering recommendation gives solar installations the opportunity to recover the costs of their initial investment, but does not guarantee them a specific rate of return on those investments; (3) the payback periods assumed by the Staff Proposed Rule are consistent with the repeated and documented claims of the solar industry and their own marketing materials; and (4) using an extreme grandfathering period, like 20 years, will simply render the Staff Proposed Rule, and this entire rulemaking process, meaningless.

First, there is nothing in the Commission's rules or policies, nor the LEDRA that guarantees any net metered solar installation will be assured or guaranteed to receive a fixed and known reimbursement rate for those systems' on-site electrical generation, particularly over the 20 year useful asset life. The same can be said of retail ratepayers: while the Commission may regulate electric utility service rates, and these rates may be fixed over a limited period of time, retail rates are often changed (via a Commission decision) over a longer period of time as warranted by circumstances and other external conditions. Indeed, it is a known element of ratemaking that utility cost of service will change even without external influence as utility plant in service is depreciated. Nothing entitles retail ratepayers to a fixed set or structure of rates over a multi-decadal time period and no such claim can be said to exist either for net metered customers and their rates.

Second, Staff believes that its proposal to tie the grandfathering period to commonly-quoted solar installation payback periods serves the Commission's ratemaking goals of equity. The proposed Staff Rule simply extends what is admittedly an over-generous, and subsidized reimbursement rate for net metered systems until such time as that system is "paid off." This policy will prevent solar installations from losing the initial value of their investment and ensure they recover their initial investment cost. What this policy will not do; however, is assure that these projects will receive some overly generous internal rate of return on the capital invested on solar energy. There is no compelling reason for the Commission to adopt such a policy, notwithstanding the position of the solar advocates in this proceeding. In addition, Staff's proposal hastens the time when similarly situated

customers (old and new solar installation owners) will be paying and receiving the same rate – i.e., they will be treated equally.

Consider, for instance, that the Commission makes no rate of return guarantees to utilities and sets rates, instead, on the basis of giving utilities an opportunity to earn a reasonable return on their investments. Regulation is often said to be a proxy for competition: regulators set prices and discipline utility rates in a fashion comparable to what would arise in competitive markets. Imprudent utility decisions are punished, through investment and cost disallowances, much like they would be in competitive markets. Likewise, utilities are given an opportunity, not a guarantee to earn a fair return on their investments. Thus, the solar advocates are misguided in noting that, somehow the Commission's policies, and the regulatory process in general, requires a fixed and guaranteed return on a solar installation's investment.

Third, the Staff proposed Rule ties the grandfather provision to commonly quoted, publicly available sources on the payback rate for solar installations, including those installed in Louisiana. Figure 23, for instance, provides a graphic from a typical advertisement for solar electricity in Louisiana that Staff downloaded from the solar developer's webpage. The payback rates provided in the marketing materials are for a 5 kW solar installation. The flier/advertisement claims that customers installing solar in Louisiana will see a 22.3 percent internal rate of return ("IRR") on a $20,000 initial investment. More importantly, the advertisement estimates that a system installed in 2016 will begin to earn a profit over costs by 2021, or approximately five years after investment.

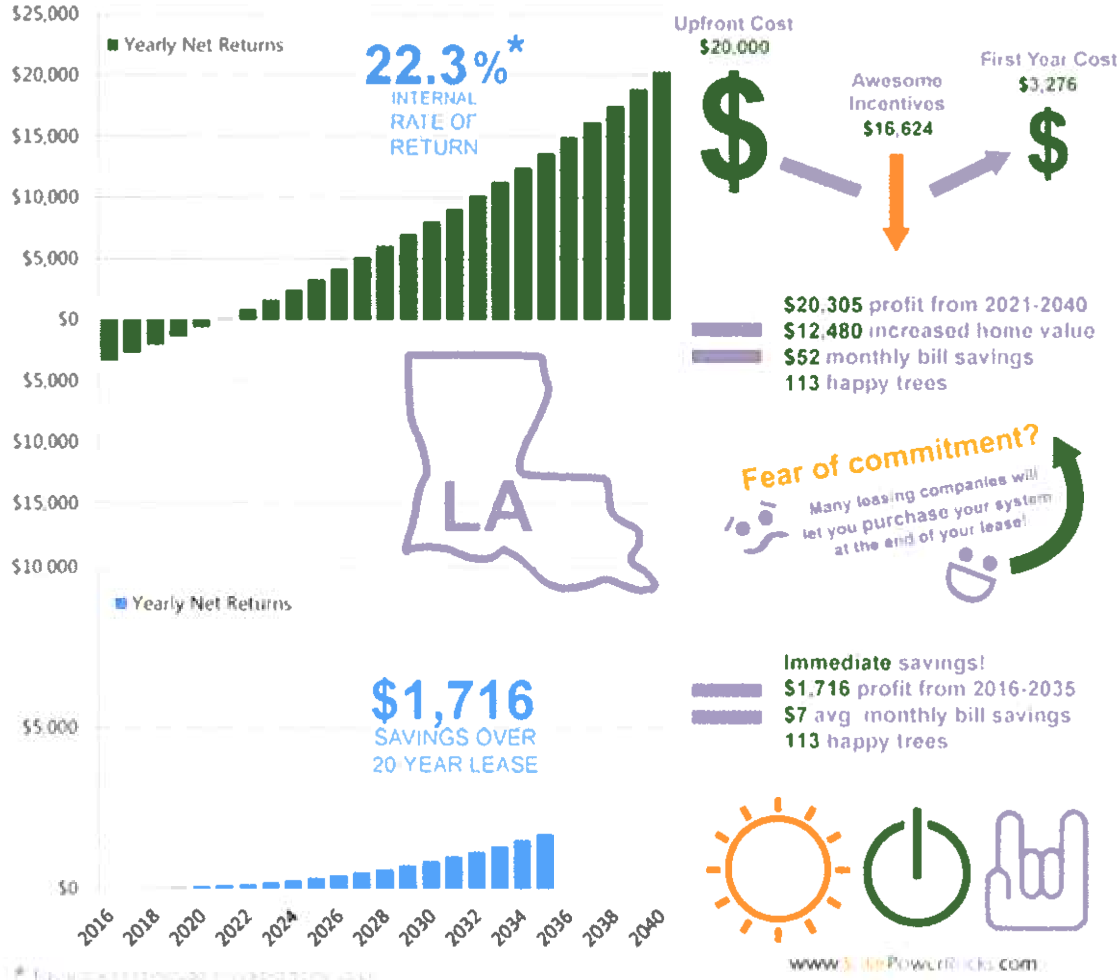

Figure 23: Louisiana Solar Pay-Back Advertisement
Source: www.SolarPowerRocks.com

Furthermore, Appendix C to Staffs Cost-Benefit Report included discussions on solar installation payback rates and the competitiveness of solar relative to grid-supplied electricity.[139] The discussion provided a figure, originally developed by the Union of Concerned Scientists that found that half of the states in the U.S. could reach grid parity by 2017.[140] Louisiana was a state where that grid parity estimate was expected to be within the next three years alone, further suggesting that a five year payback is reasonable.

[139] Dismukes, David (2015), *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers,* Appendix C at 24-24.
[140] Dismukes, David (2015), *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers,* Appendix C at 25.

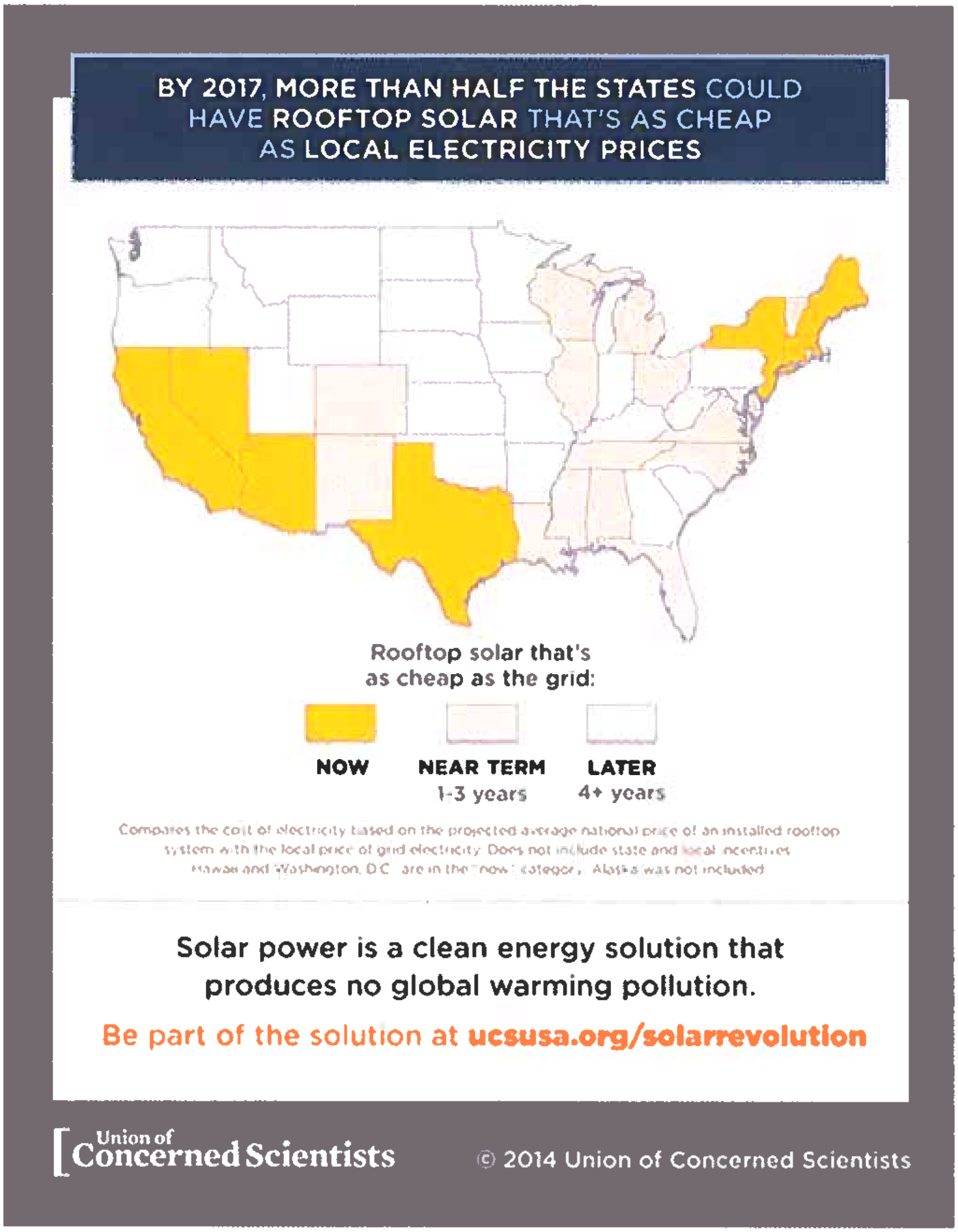

Figure 24: UCS Analysis of Grid Parity

Source: Jacobs, Mike. 2014. How much does rooftop solar power cost? Grid parity here or coming in more than half of U.S. states. Union of Concerned Scientists. Available at: http://blog.ucsusa.org/how-much-does-rooftop-solar-power-cost-grid-parity-633.

Other available payback estimates state similar, if slightly longer estimated payback periods for solar investment. A May 24, 2016 sponsored content piece by South Coast Solar and Liberty Self Storage that ran in the New Orleans Times Picayune assured readers that the typical payback period of solar systems ranged from seven to eight years.[141]

[141] "4 things to know about solar panels and your solar system." (May 24, 2016) *The Times-Picayune*, article sponsored by Liberty Self Storage. Available online at: http://blog.nola.com/sponsored/2016/05/4_things_to_know_about_solar_p.html

Likewise, "Solar-Estimate.org," which appears to be a solar marking organization designed to promote solar installers, maintains an online solar cost-effectiveness calculator to inform interested people on the relative economics of solar generation systems in their state.[142] This calculator estimates that a 9.51kW system in Louisiana would have an upfront cost associated with it of nearly $22,000. However, the calculator also estimates that the average lifetime savings of this system would be $50,711. In all, the online solar cost calculator finds that a 9.51kW solar system in Louisiana has a payback period of 9 years, 3 months.

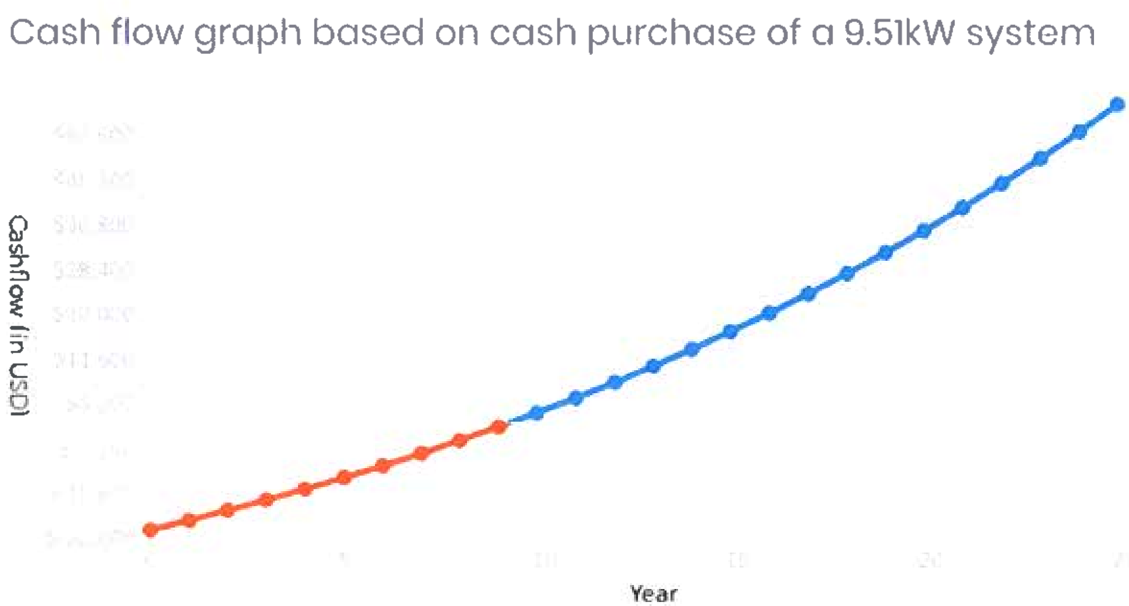

Figure 25: On-line Solar Cost-Effectiveness Calculator, Louisiana
Source: Solar-Estimate.org. Available online at: https://www.solar-estimate.org/solar-panels/louisiana

Fourth, using an extreme grandfathering period, like 20 years, will simply render the Staff Proposed Rule, and this entire rulemaking process, meaningless. Solar advocates in this proceeding suggest that a 20 year grandfathering period would be preferable to the Staff proposal. The problem with this recommendation is that effectively would make every solar installation, prior to the time of the Rule's approval, eligible for reimbursement at full retail rates for the next two decades. If the solar advocates' recommendation is adopted, it will not remedy the existing cross-subsidy, which is already prohibited under LREDA, but maintain this subsidy for the next twenty years. Further, since solar installations have decreased over the most recent two years, the

[142] "Louisiana solar power facts," Solar-Estimate, Available online at: https://www.solar-estimate.org/solar-panels/louisiana.

overwhelming majority of the capacity installed over the past decade would be locked into this over-generous subsidy rendering the reforms envisioned in this Rule meaningless for over 68 percent of the behind-the-meter capacity active in Louisiana.

Figure 26 provides the cumulative and incremental solar installations in Louisiana since 2008 in capacity terms. A point ignored by the solar advocates is that a large portion of the solar installations in the state will likely receive more than a five year subsidy even if the Commission approves the Staff proposed Rule. Consider that a solar generator installed in 2008 will have received solar subsidies for a decade (2018 to 2008) and will receive an additional five years of subsidies during the proposed grandfathering period if the Commission accepts the Staff recommendation. In other words, a 2008 system will receive a 15-year subsidy in total if the Staff Proposed Rule is approved by the Commission in its current form. Likewise, solar systems that were installed as recently as 2014 and 2015, the two highest installation years on record, will receive subsidies lasting nine and eight years, respective – not a mere five years alone. Thus, the Staff Proposal for a five year grandfathering period represents a more than generous and equitable transition for Louisiana solar installations.

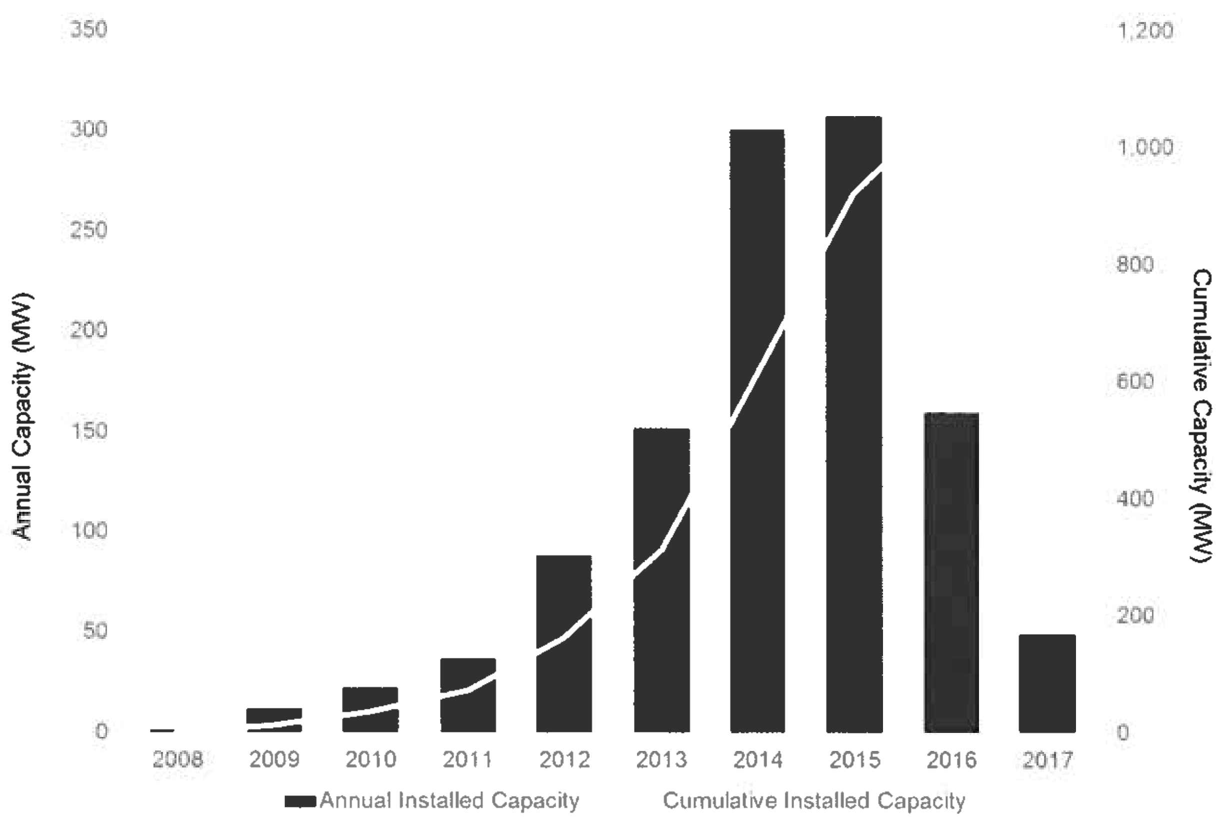

Figure 26: Louisiana Incremental and Cumulative Net Metered Capacity

Source: Dismukes, David (2015), *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers;* and LPSC Net Metering Annual Reports.

Finally, it is a basic tenant of public utility regulation that similarly situated customers should be treated in similar fashions free from undue discrimination. By treating similarly situated customers equally, undue discrimination in rates and the provision of service is avoided. If a 20 year grandfathering provision is adopted, similarly situated customers (one who installed solar generation in 2017, and one who installed the same sized solar generation system in 2019) will be treated dramatically different for 20 years. No sound reasoning or ratemaking policy supports such a result.

2.2.5. Community Distributed Generation

a. **Parties Position:** The Staff proposed Rule includes provisions to require utilities to consider developing tariffs for community distributed generation, a process that allows similarly-situated groups of customers to "group fund" a renewable energy installation rather than funding an individual rooftop or residential-based system alone.

All parties were generally supportive of the proposed Rule's inclusion of a provision for community distributed generation. The Sierra Club noted that community solar is a fast-growing segment of the solar market, and that it is a critical policy for expanding access to distributed generation to customers who cannot install solar at their home or business.[143] AAE noted that a National Renewable Energy Laboratory ("NREL") study found that as many as 49 percent of households and 48 percent of businesses are unable to install their own solar systems due to a variety of factors that may be mitigated by community distributed generation policies.[144] Likewise, Wilhite expressed support for consideration of the policy.[145]

Some jurisdictional utilities, while supportive of the proposal, request language changes to the proposal to provide additional clarity. ALEC requests that the Commission apply a "reasonableness" standard to the allocation of rate credits from a community distributed generation facility, due to the potential complexities

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[143] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 19.

[144] Comments on Behalf of the Alliance for Affordable Energy, at 6.

[145] Comments on Behalf of Wilhite Energy, LLC., at 3.

involved in allocating various credits to multiple customers.[146] Cleco suggests that the proposed Rule should incorporate the accepted definition of ownership under Louisiana law, which provides that "ownership" is the right that confers on a person direct, immediate, and exclusive authority over a thing.[147] Cleco suggests this addition to avoid any confusion over ownership of a community distributed generation facility.[148] Cleco also states that it is unclear from the proposed Rule how a utility will determine how and when to apply any credits to the members of the community distributed generation organization.[149]

Entergy notes that it interprets the proposed provision as being limited to utility customers who collectively pool their resources to own and operate a community distributed generation facility, thus excluding third party ownership. Entergy requests, like Cleco, that the proposed Rule incorporate by reference the accepted definition of ownership under Louisiana law to provide additional clarity on the prohibition of third party ownership. Entergy provides as an example that an apartment building owner should not be allowed to install a distributed generation system on behalf of his or her tenants as the tenants have no ownership of the facility.[150]

Entergy also notes a perceived ambiguity with regards to the proposed Rule requirement of proximity. Currently, the proposed Rule only restricts a community distributed generation facility to being located within the same electric service territory as all of its member distributed generation customers. Taken to the extreme, Entergy notes that this could be interpreted as allowing distributed generation customers living in Lake Charles, Monroe, and Metairie to own a community distributed generation facility in Baton Rouge as all locations are technically within Entergy's electric service territory. Entergy expresses that it does not believe this was the intent of the proposed provision, and requests clarity on whether or not the Commission intends for there to be any proximity limitations on community distributed generation facilities.[151]

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[146] Comments of the Association of Louisiana Electric Cooperatives, inc., at 3 and 4.
[147] Comments of Cleco Power, LLC., at 2.
[148] Comments of Cleco Power, LLC., at 2.
[149] Comments of Cleco Power, LLC., at 3.
[150] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 4.
[151] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 5.

b. **Staff Response:** The purpose of Staff's proposed community distributed generation provision was to provide customers the opportunity to collectively pool resources to own and operate a community distributed generation facility. It was not intended to be extended to third party ownership, such as an apartment building owner installing a distributed generation facility on behalf of the tenants of the building. In such an example, the tenants would receive financial compensation for the operations of the net metered system even though they did not incur the financial costs associated with the original installation of the net metered system. This is true even if the customer compensates the owner of the system through indirect means, such as a monthly rental agreement. The customer does not own the net metering system, as suggested by some parties. Therefore, Staff has amended its proposed Rule to include a reference to La Civil Code Article 477, which defines ownership as the "direct, immediate, and exclusive authority over a thing."[152]

Staff however does not agree with Cleco that the proposed Rule is unclear as to how a utility will determine how and when to apply any credits to members of the community distributed generation organization's bills. Section 4.2.4 states that the utility shall credit each community distributed generation organization member allocated bill credit on the customer's next bill for electric service. In other words, each month, pursuant to Section 4.2.1, a utility shall determine the monthly generation from the community distributed generation facility, and associated bill credits for the members of the community distributed generation organization. The utility will apply this bill credit to each member's bill for electric service on the bill following the determination of the bill credit.

Likewise, Staff does not agree that the proposed Rule is unclear as to how a utility will determinate appropriate bill credits for each community distributed generation organization member. Section 4.2.2 states that all electrical energy supplied by the community distributed generation facility will be valued at the associated electric utility's avoided cost rate. Therefore, all bill credits from the community distributed generation facility will be the value of electric generation priced at the relevant utility's avoided cost rate. Section 4.2.5 furthermore states that the allocation of bill credits "shall be determined by the Community Distributed Generation

[152] LA Civ Code 477.

Organization." In other words, the community distributed generation organization will inform the utility prior to operations of the appropriate allocation of bill credits from the community distributed generation facility and will be required to update the utility to the extent the organization's allocation changes. Presumably, such allocations will be something as simple as percentage allocations. However, to the extent there is a dispute between the utility and a community distributed generation organization regarding the proposed allocation formula, including a proposed allocation formula that is overly complex or otherwise unworkable, it is subject to approval by the Commission, as provided in Section 4.2.5.

Staff also does not agree with Entergy's concerns related to the perceived ambiguity with regards to the proposed Rule's requirement of proximity. Entergy is correct that the proposed Rule could be read as allowing distributed generation customers living in Lake Charles, Monroe, and Metairie to own a community distributed generation facility in Baton Rouge, since all locations are technically within Entergy's electric service territory. However, generation at the facility would be appropriately valued at the avoided cost rate associated with the location the facility is operating, and not at the locations of relevant community distributed generation organization members. Furthermore, Section 1.2.8.1 sets clear limits on the size of such facilities – 25 kW for residential use, and 300 kW for commercial or agricultural use. Therefore, the proposed Rule is limited to small-scale projects only, likely diminishing ELL's proximity concern.

2.2.6. Standard Interconnection Agreement

a. **Parties Position:** Entergy, Cleco, and SWEPCO expressed concern with the standard interconnection agreement attached to the proposed Rule. Cleco requested that the Commission clarify that the illustrative form of the agreement is just that, merely an illustration. Therein, a utility is free to develop and file for approval with the Commission its own standard interconnection agreements.[153] Entergy's concern also related to the illustrative nature of the attached interconnection agreement.[154] Likewise, SWEPCO states that it would prefer to continue to offer its existing interconnection agreement rather than begin to offer a more generic agreement that is standardized state-wide.[155]

ALEC in its comments stressed the importance of having standardized interconnection agreements in place with all distributed generation customers prior to the installation of a distributed generation facility. ALEC argued that it is imperative that a utility be aware of the existence, details, and location of all distributed generation facilities within the utility's service area for safety reasons such as during post-outage repairs.[156]

GSREIA requested that the 45-day turnaround for the utility to review a standard interconnection agreement be shortened to 14 days. GSREIA states that there is little justification for the long delay in response to an interconnection request.[157]

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[153] Comments of Cleco Power, LLC., at 4.
[154] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 12.
[155] Comments on Behalf of Southwestern Electric Power Company, at 5.
[156] Comments of the Association of Louisiana Electric Cooperatives, inc., at 4.
[157] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 11.

b. **Staff Response:** Sections 5.1.1 and 5.2.1 of the Proposed Rule have been modified to clarify that the standard interconnection agreement attached to the proposed Rule as appendix A is intended to be an illustrative example of a standard interconnection agreement, which utilities can adopt if they so choose, or continue using their established interconnection agreement. While the prior proposed language, and appendix A itself, have been elements of previous Commission Net Metering Rule, most electric utilities operating in Louisiana have created separate standard interconnection agreements governing net metering installations in their respective service territories. There have been no indications that these agreements have in any way prejudiced the installation of distributed generation technologies relative to the illustrative example included in the Commission's Rule.

Likewise, Section 5.2.4 has been modified to shorten the turnaround for the utility to review a standard interconnection agreement from 45 days to 14 business days. As Louisiana electric utilities have gained increased experience interconnecting distributed generation systems to their systems, the efficiency of the process has improved as well. As stated by GSREIA, there would appear to be little justification for a utility to require 45 days to evaluate the interconnection of a proposed distributed generation system, barring violations of applicable safety standards and/or power generation limits preventing approval of the proposed interconnection. Even in such situations, the expedited time-frame will provide installers quicker feedback associated with issues that the utility requires to be remedied prior to permitting interconnection of the system.

2.2.7. Other Issues Raised by Individual Parties

a. **ALEC Issues:** ALEC argues that the Staff's proposed Rule appears to require that any new distributed generation tariffs be filed with the Commission and therefore subject to the Commission's publication period and the ability of parties to protest/request intervention in a docketed proceeding. ALEC argues that this is a departure from the common Commission practice of not requiring notice and publication of requested tariff changes. Given that Staff proposed this publication language under the general discussion of "Meter and meter installation charges," ALEC argues that it would be beneficial to all parties involved for Staff to outline if the envisioned scope of a potential contested docketed proceeding would encompass only the issue of whether the proposed charge to cover the incremental costs of meter installation should be allowed, or if Staff envisions that other issues related to a utility's filed tariff will be subject to such a contested proceeding.[158]

Staff Response to Individual ALEC Issues: Staff does envision that tariffs filed under the new Rule will go through the notice provisions, particularly the initial tariffs that will be filed immediately after approval of this Rule. This is not just related to metering charges and provisions, but the entire tariff and its terms and conditions. Staff believes it is important that these tariffs be thoroughly reviewed, and that parties, including solar advocates and Staff, be given the chance to assure that utilities are in compliance with the new Rule, and have considered all of the terms and provisions included in the new Rule, particularly those associated with setting the DER reimbursement rate. Staff does agree that future changes to these tariffs, or updates, can be limited in scope and can be noticed as such.

[158] Comments of the Association of Louisiana Electric Cooperatives, Inc., at 1 and 2.

b. **AAE Issues:** AAE claims that the Staff proposed Rule will allow utilities to impose unforeseeable future charges on distributed generation customers. AAE opposes the provision's allowance of potential charges to recover lost revenues on policy grounds, and on practical grounds that it may potentially create an unreasonable series of expensive litigated proceedings before the Commission.[159]

Staff Response to AAE Issues: Staff disagrees with AEE's position on lost revenues and notes that the referenced language allowing for the recovery of lost revenues was language that existed in previous iterations of the Commission's Net Metering Rule before the current staff proposed changes. Staff also notes that, under current regulatory practice in Louisiana, the recovery of lost base revenues from DER, or any energy efficiency application, already occurs through most utilities' formula rate plans ("FRPs"). These FRPs allow utilities to annually "true-up" revenues, expenses and investments and to modify rates accordingly. If revenues are down due to increases in DER generation, those revenue short falls will be accounted for in the FRP reconciliations. The only thing the "lost revenue" provision may do, within the context of the currently proposed Rule, is to explicitly account for those losses, and, potentially, assign those losses to the customers in a fashion that differs from the allocations used in the FRP process. However, per the Staff proposed Rule, utilities will have to make a filing, and prove the merits of any proposal of this nature. Thus, AEE's insinuation that these DER-related revenue losses will automatically be recovered, is without merit: DER-related revenue losses will only be recovered in a fashion that the Commission deems is in the public interest.

c. **Cleco Issues:** Cleco supports the Staff proposal to limit a residential distributed generation installation to 25 kW and a commercial installation to 300 kW. Cleco also supports the Staff proposal to restrict individual installation sizes to those that are no larger than 100 percent of the customer's expected aggregate electric consumption for a year, as calculated based on an average of the prior two 12-month periods of actual electric usage.[160]

[159] Comments on Behalf of the Alliance for Affordable Energy, at 4.
[160] Comments of Cleco Power, LLC., at 4.

<u>Staff Response to Cleco Issues:</u> No additional Staff comment.

d. **Entergy Issues:** Entergy provides a large number of editorial revisions and clarifications, most of which are adopted by Staff and are included in the revised Rule offered to parties for additional comment.

Entergy also provides a number of substantive comments that were not raised directly by other parties. First, Entergy strongly urges the Commission to retain its long-standing meter testing standards that have been in place historically and remove the distributed generation-specific requirements in the proposed Rule.[161] Entergy argues that the proposed testing standards included in the proposed Rule would be impractical, and unnecessarily exceed the Company's current standards.[162]

In a similar vein, Entergy notes that the proposed Rule allowed a utility to assess a one-time charge to recover costs associated with an additional meter or meters if requested by the distributed generation customer.[163] However, Entergy expresses a concern that the proposed language does not allow for the recovery of additional costs the utility may face to either bill distributed generation customers manually or modify its billing system to perform the "necessary complex calculations in an automated fashion."[164] Entergy argues that these costs should not be socialized to all customers, but instead borne by distributed generation customers; however, the utility also noted that it had "neither an estimate of these costs nor a proposed method of recovering them from affected customers."[165]

Entergy also states that the Staff's proposed Rule represent a departure from the Commission's current Rule that require interconnection customers to pay 100 percent of their interconnection costs upfront. Entergy interprets the proposed Rule as allowing for these costs to be spread over time, needlessly exposing a utility to financial risk in cases of customer default.[166] Furthermore, Entergy argues that the proposed Rule is unclear as to whether electric utilities will be allowed to collect necessary carrying costs on unamortized balance.[167]

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[161] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 7.
[162] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 7.
[163] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 7.
[164] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 8.
[165] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 8.
[166] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 9.
[167] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 9.

Entergy also notes that the Staff Rule proposal overstates the Commission's authority regarding Renewable Energy Credits ("RECs") relative to current practices.[168] Specifically, Entergy argues that the Commission only has the authority to determine the eligibility and applicability of RECs as it applies to Commission policymaking. While not explicit, it appears that Entergy believes the proposed Rule should be revised to allow distributed generation customers to participate in other state REC markets (or voluntary markets) in the absence of the development of a specific renewable energy market (REC market) in Louisiana.

Finally, Entergy expresses concerns regarding provisions within the proposed Rule that require utilities to audit distributed generation customers' systems for compliance with the Commission's Rule. Entergy requests that these provisions be modified to permit the utility to audit a system if has concerns that a customer's system was not in compliance with the Commission's net metering Rule.[169] Entergy argues that the proposed Rule's penalties for installation-specific rule non-compliance is potentially "excessive" and suggests that, rather than take a unilateral disconnection action, utilities be required to report rule violations to the Commission and disconnect customers only after a Commission finding that an installation is in violation of the Commission's standards.[170]

<u>Staff Response to Entergy Issues:</u> Many of Entergy's complaints with regards to the proposed Rule are associated with language that exists in the Commission's original net metering Rule and have been maintained in Staff's current proposals, in large part, to maintain some degree of continuity between the two rules. Entergy's concerns about meter testing standards, as well as the concerns about spreading interconnection costs over time both relate to language in the newly proposed Rule that was carried over from the prior Rule. Staff will attempt to address and reconcile these concerns in the suggestions below.

Staff agrees that the proposed Rule unnecessarily duplicates the Commission's general policy on meter testing. Further, the provisions allowing any party involved to request the recovery of interconnection costs over a reasonable period of time is unclear regarding the issue of carrying costs and how the risk of default could be

[168] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 9.
[169] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 10.
[170] Entergy's Comments in Response to LPSC Staff's Phase II Notice of Proposed Modified Net Metering Rules, at 11.

passed along to other ratepayers. Staff, therefore, has simply eliminated these provisions (Sections 3.2.3 and 4.4.3.) given (a) their ambiguity and (b) the fact that, given Entergy's comments, no reconciliation of these provisions has been attempted over the past several years, raising question about their importance and merit in supporting DER installations.

Further, Staff agrees with Entergy's proposed changes to the existing Rule's policy on the ownership of RECs. Section 4.6 has been modified to clarify that the Commission has the sole right to determine the eligibility and applicability of RECs, as it relates to Commission policymaking. In the absence of a Louisiana renewable portfolio standard, owners of distributed generation systems retain ownership of RECs, and are free to participate in markets outside of Louisiana.

Finally, Staff disagrees with Entergy's proposal regarding to the recommended changes to utility auditing requirements. Staff's reading of the proposed Rule does not institute a specific time period or procedure associated with utility review of generation systems on distribution systems in the State, nor was it intended to. Instead, the Rule require that distributed generation customers must make facilities available to utility inspection, whether as part of routine inspections or in furtherance of a utility concern. To the extent Section 5.3 is intended to place any requirement on electric utilities, it is simply a reinforcement of the requirement of electric utilities to oversee the safe operations of distribution systems, including as it relates to distributed generation systems operating improperly, potentially jeopardizing the safe operations of the electrical grid.

e. **GSREIA Issues:** GSREIA recommends that the cap for distributed generation facilities be increased from 300 kW to 2 MW for commercial and community solar installations. GSREIA states that Louisiana's commercial cap is particularly low compared to most states and restricts many businesses from benefitting from solar energy.[171] GSREIA also recommends that the cap on residential solar installations be increased from 25 kW to 50 kW but offers no evidence regarding why the Commission's current Rule on this issue is deficient or how the current Staff proposal compares to other state practices.

[171] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 11.

GSREIA also argues that the Staff proposal will subject solar distributed generation installations to unfair utility fees and charges.[172] GSREIA recommends that additional charges be capped at a certain amount to protect ratepayers from these potential predatory practices but offers no insights nor specifics on how that cap should be set, nor does it offer any suggestions on how these unrecovered costs should be treated for regulatory purposes (e.g., should they be recovered "below the line" or from other, non-DER customers?).[173]

GSREIA additionally argues that the proposed Rule should allow the proposed grandfathering provisions to be transferable on the sale of a property containing a DER system.[174]

Finally, GSREIA argues that RECs should remain the property of the owner of the distributed generation system.[175]

Staff Response to GSREIA Issues: Staff believes the existing cap on traditional distributed generation systems provides an important check on preventing large wholesale-sized systems from being inappropriately installed as small distributed generation systems. Therefore, Staff does not support the requested removal of this restriction. Likewise, Staff does not support the proposed cap on utility fees and charges since such a cap prejudges the reasonableness and prudence of such costs. Each utility will be required to prove the reasonableness of its costs to the Commission and the Commission certainly has within its power to assess whether such costs are reasonable without a cap.

Lastly, Staff does not support the request for transferability associated with the grandfathering provision. The purpose of the proposed grandfathering clause is to provide an orderly regulatory and market transition from the Commission's prior net metering Rule to Staff's newly proposed DER Rule for those customers making the decision to install a DER application. Allowing the transfer of a grandfathered compensation structure to a

[172] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 6.
[173] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 12.
[174] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 12.
[175] Comments of the Gulf States Renewable Energy Industries Association on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 11.

customer who did not make a capital investment to install a distributed generation system would unnecessarily hinder this goal of an orderly transition.

Finally, Staff agrees with GSREIA regarding the proposal to allow RECs to remain the property of the owner of the distributed generation system. Staff has therefore revised Sections 4.6.1 and 4.6.2 to reflect this change.

f. **PosiGen Issues:** PosiGen recommends that the Commission examine the potential for solar distributed generation to serve low income ratepayers by offering a retail two cent adder to the avoided cost reimbursement rate for Louisiana ratepayers who are at or below 50 percent of the area's median income.[176]

Staff Response to PosiGen Issues: Staff believes that the current rulemaking is not the appropriate proceeding to evaluate a new subsidy of this nature.

g. **Sierra Club Issues:** The Sierra Club argues that the Staff proposal to remove the grandfathering provisions for installations that make changes or modifications to their system is both unfair and potentially unsafe.[177] The Sierra Club notes that in its view, the current Rule could render the mere maintenance or repair of an existing distributed generation system as triggering the removal of existing grandfathering status.[178] Sierra Club recommends that the provision removing grandfathering for modified installations be removed or alternatively rephrased to eliminate grandfathering only in instances of "significant" modification that result in large generation capacity increases.[179]

Likewise, Sierra Club requests that Staff remove the proposed Rule's provisions that will eliminate grandfathering for DER installations that transfer ownership. Sierra Club further argues that a strict interpretation of this Rule would also apply to installations that include not only a sale of property, but other types of property transfers such as an inheritance, gift, or divorce. Moreover, the Sierra Club notes that it is unclear whether a partial transfer of a property would also trigger a loss of grandfathered status.[180]

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[176] Comments of PosiGen of Louisiana, LLC on the Louisiana Public Service Commission's Phase II Notice of Proposed Modified Rules and Request for Comments, at 10.
[177] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 15.
[178] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 16.
[179] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 16.
[180] Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 16.

The Sierra Club argues that the proposed Rule provide that the Commission has the sole right to issue RECs associated with distributed generation. However, the Sierra Club states that by claiming this exclusive right, the Commission is depriving Louisiana customers of a source of revenues associated with registering their systems in other renewable energy tracking systems.[181]

Staff Response to Sierra Club Issues: Staff disagrees with the Sierra Club's characterization that the proposed Rule would allow for the removal of grandfathering status merely due to maintenance activities or the repair of an existing system. In such an event, the system would continue to be certified as interconnected prior to the grandfathering date. Only changes or modifications requiring changes to the distributed generation system's interconnection agreement fall into this category. However, in recognition of the Sierra Club's concern, Staff has revised the proposed Rule to clarify that only "material" changes or modifications trigger the loss of grandfathering status.

Lastly, Staff agrees with Sierra and other parties about REC ownership and has modified the proposed Rule to allow owners of distributed generation systems to retain ownership of all RECs associated with generation from the system.

h. **SWEPCO Issues:** SWEPCO recommends that language should be considered stating that only a percentage of distributed generation's nameplate capacity would be utilized in a utility's Integrated Resource Plan ("IRP").[182] SWEPCO provides as an example that SPP utilizes a 10 percent capacity value for distributed generation solar resources until three or more years of actual data is available.[183]

SWEPCO also states that it supports the efforts in the proposed Rule to address issues associated with transferring credits when a net metering customer has multiple accounts. However, SWEPCO suggests adding a restriction to limit such transfers to those at the same physical location. This would reduce administrative burdens.[184]

181 Sierra Club's Comments in Response to Phase II Notice of Proposed Modified Rules, at 17.
182 Comments on Behalf of Southwestern Electric Power Company, at 2.
183 Comments on Behalf of Southwestern Electric Power Company, fn. 1.
184 Comments on Behalf of Southwestern Electric Power Company, at 4.

Staff Response to SWEPCO Issues: Staff does not agree with SWEPCO that it is either necessary or appropriate to prescribe within the proposed Rule's restrictions for the incorporation of distributed generation benefits within utility IRPs. The reason for this is that two RTOs, SPP and MISO, operate within the State, both of which have different rules and regulations concerning the valuing of benefits associated with distributed generation systems for system reliability purposes. This being said, Staff believes the Commission is fully aware that renewable generation systems, being intermittent by nature, have capacity benefits that differ from traditional electric generation units, and that this understanding should be incorporated into any inclusion of said benefits for planning purposes.

Staff also does not agree with SWEPCO's proposal to restrict the transferring of credits to only accounts at the same physical location. Because under the proposed revised Rule, all bill credits are valued at the utility avoided cost rate, there is no complicated netting process involved, but merely an accounting of the bill credit to a requested account. Staff does not foresee this being abnormally administratively burdensome on utilities.

i. **WalMart Issues:** WalMart argues that DER installation size restrictions should be designed around an individual customer's peak load, not some arbitrary capacity limit, like 300 kW for commercial systems. WalMart recommends elimination of the 300 kW capacity limit for commercial DER installations.[185] In the alternative, WalMart requests that the Commission permit companies to file a request for approval of multiple systems greater than 300 kW in a single docket filing.[186]

WalMart also recommends removal of the proposed Rule's lost revenues provision. WalMart argues that the lost revenue provision is unnecessary since most jurisdictional utilities have FRPs that compensate a utility for all lost utility base revenues.[187]

Staff Response to Walmart Issues: Staff believes the existing cap on traditional distributed generation systems provides an important check on preventing large wholesale-sized systems being inappropriately installed as small distributed generation systems. Therefore, Staff does not support the requested removal of this

[185] WalMart Stores Inc.'s Response to Louisiana Public Service Commission Staff's Request for Comments, at 5-6.
[186] WalMart Stores Inc.'s Response to Louisiana Public Service Commission Staff's Request for Comments, at 5-6.
[187] WalMart Stores Inc.'s Response to Louisiana Public Service Commission Staff's Request for Comments, at 7.

restriction. However, Staff takes no issue with WalMart's alternative request that companies be allowed to file a request for approval of multiple distributed generation systems greater than 300kW within a single docketed filing.

The referenced language allowing for the recovery of lost revenues was language that existed in previous iterations of the Commission's Net Metering Rule. However, there have been no proposals Staff is aware of where a utility has requested recovery of lost revenues associated with distributed generation systems. Furthermore, such a recovery mechanism is arguably of little value in the context of current utility regulation in Louisiana, where all major regulated electric utilities operate under formula rate plans which allow for recovery of reduced utility revenues. For these reasons, Staff has removed the referenced provision allowing for recovery of lost revenues.

j. **Wilhite Issues:** Wilhite recommends that a technical conference be established before further action on the proposed Phase II Rule. Wilhite suggests the technical conference will (1) determine social and environmental benefits of NEM, (2) explore the compelling interest in NEM by fuel-based distributed generation or whether controllable distributed generation is better served by a review of the current distributed generation tariffs, and (3) determine if the proposed Rule is responsive to the new normal of solar participation in a post-state tax credit market.[188]

Staff Response to Wilhite Issues: Staff disagrees with Wilhite regarding the need for a technical conference in the current proceeding. The Commission opened the current investigation reviewing changes to the Commission's Net Metering Rule at its December 2015 Business and Executive Session. Through two phases, the Commission and all intended stakeholders have had the opportunity to review issues associated with distributed generation policy for approximately two and a half years. Staff sees little benefit in an additional technical conference as proposed by Wilhite.

[188] Comments on Behalf of Wilhite Energy, LLC., at 2.

<u>Section III</u>

Summary of Proposed Rule Change

Section III: <u>Summary of Proposed Change</u>

<u>Purpose (Section 1.1):</u> Section 1.1 defines the purpose of the Commission's distribution-level customer energy generation Rule as being able to define the terms and conditions under which electric utilities provide service to behind-the-meter, distribution-level generation. In this, the proposed Rule establishes the Commission's intention in sub-sections 1 and 2 that its Rule will be construed as facilitating the development of all cost-effective distributed generation ("DG"), in a fair, open, and non-discriminatory manner to the customer developing the DG and the technology being utilized.

Subsection 3 outlines the proposed position that all, non-grandfathered, DG customers in Louisiana will be compensated for electricity sold to the distribution grid at rates that are cost-based. Cost-based rates, also called avoided costs, are defined in greater detail in Section 6.2 of the Rule. However, subsection 3 notes that utility cost-based rates shall reflect the value of the commodity (electricity) being provided to the utility. This potentially includes any geographic, capacity oriented, and/or environmental benefits to the DG provided energy, to the extent these can be quantified. Subsection 4 further clarifies the proposal that all DG-related costs, to the extent not specifically addressed elsewhere in the Rule, be recovered from DG customers through specific tariffs. The subsection clarifies the Commission's position that the Commission's Rule is not intended to promote the subsidization of DG customers.

Subsections 5 and 6 outline ongoing utility responsibilities. Specifically, the proposed Rule defines the electric utilities as being responsible for the ongoing monitoring of DG installations for compliance with the Commission's Rule. Likewise, the Commission desires that DG installations be viewed as generation resources for local utilities and expects utilities to account for this resource in future resource planning processes filed with the Commission.

<u>Definitions (Section 1.2):</u> Section 1.2 sets definitions to be used in the proposed Rule. Most of the definitions used in the proposed Rule are present in the Commission's existing NEM Rule, and simply reorganized in the proposed Rule. Subsections 5 and 6, however are new definitions to define and allow for community distributed

generation facilities and associated organizations within the proposed Rule. Subsections 7 and 8 redefines net energy metered customers and facilities within the Commission's existing NEM Rule as distributed generation customers and facilities to reflect the change in the Rule's scope from outlining net metering terms to promoting distributed generation resources. Likewise, the proposed Rule eliminates the existing definition of various renewable-sourced fuels to reflect the change in the Rule's scope from promoting renewable fueled DG technologies to promoting all small-scale DG technologies. Subsection 9 clarifies that an investor-owned utility, for purposes of the proposed Rule, is intended to be consistent with the definition in La. R.S. 45 § 1161. Subsection 10 establishes the effective date of the proposed Rule as consistent with the forthcoming Commission Order. Finally, subsections 11 through 14 establish definitions for interconnection costs, parallel operations, renewable energy credits, and a residential customer.

Staff's previous analysis of the Commission's net metering Rule examined the potential for generation facilities to be owned by third parties. Staff's investigation was focused on a situation where the end use customer enters into an agreement with a leasing company for a fixed price and fixed term for equipment installed at his or her premise. Staff concluded that "third party ownership of net metering equipment can be beneficial (...)." Since Staff's prior investigation, there have been movements in other jurisdictions to allow for "Community Distributed Generation," or "Community Net Metering," which allows for multiple individual utility customers to own and purchase energy from a single small-scale DG facility. At the request of parties, Staff has included a reference to Louisiana Civil Code Article 477(A) in Subsection 1.2.5.2, regarding the definition of ownership in conjunction in Louisiana law.

Scope (Section II): Section 2 defines the applicability of the proposed Rule to apply to all DG customers taking service under the provision of a utility's DG tariff. The section also clarifies that the Rule is not intended to affect or replace any Commission approved general service regulation other than those pertaining to the regulation of DG. The provisions of Section 2 are currently elements of the Commission's NEM policy.

Distributed Generation Requirements (Section III): Section 3 defines the metering requirements for utilities connecting DG customers to the larger electric grid. Subsections 1, 2, and 3 pertain to the accuracy of electric meter arraignments for DG customers. The proposed Rule does not change the Commission's existing policy contained within its NEM policy that provides that additional meters to measure electrical inflows and outflows, or in situations where systems are separately metered, should yield the same results as if a single meter is utilized. Billing errors resulting from faulty meter operations will result in appropriate credits or payments being applied to the DG customer or community DG customer's next billing cycle.

Subsection 4 clarifies that DG customers will not be charged for replaced metering equipment to allow for the interconnection of DG technologies, unless an additional meter or meters is/are requested by the DG customer. This includes the cost of basic metering equipment required to serve a DG customer. The costs associated with any required replacement of a single electrical meter to adequately record the inflows and outflows from a DG customer shall be rate-based and recovered through rates, like all meter expenses.

Billing for Distributed Generation Facilities (Section 4.1): Section 4.1 defines that DG customers will be billed for electrical use consistent with the applicable utility's current standard rate schedule, with appropriate rider schedules. For electricity generated and fed back to the electric utility, the customer shall be billed at a rate consistent with the utility's approved avoided cost rate – except in situations where the customer is grandfathered from existing tariffs pursuant to Section 7.1. Subsection 4.1.3 addresses situations where a DG customer may generate more electricity in a monthly billing cycle than that supplied by the electric utility, and thus has negative usage for the cycle. In these situations, the customer will receive a zero charge for the cycle and will be credited on the next billing cycle for the excess generation at a rate equal to the utility's approved avoided cost rate. If, in the final month the DG customer takes service from the utility, the customer generates more electricity than that supplied by the electric utility, the electric utility shall monetarily compensate the customer for the balance owed.

<u>Billing for Community Distributed Generation Facilities (Section 4.2):</u> Similar to the billing arraignment for DG facilities set forth in Section 4.1, all electricity generated and exported to the electric grid by community DG facilities under the proposed Rule will be compensated at the utility's approved avoided cost rate. The monetary value of electricity generated by the community DG facilities will be allocated and applied to each member of the community distributed generation organization. The allocation to each member shall be determined by the community distributed generation organization, and subject to approval by the Commission.

<u>Sizing of Distributed Generation Facilities (Section 4.3):</u> Section 4.3 clarifies that approved DG facilities should be appropriately sized to produce no more than 100 percent of the customer's expected aggregate annual electric consumption. Utilities submitted comments with regards to the Commission's existing NEM Rule that it allowed customers to persistently have negative usage. While Staff disagrees with this interpretation of the Commission's existing Rule, Section 4.3 has been added to the proposed Rule to remove all uncertainty that it is not the view of the Commission that its Rule should be used to justify the construction of over-sized DG systems.

<u>Additional Charges for Distributed Generation Facilities (Section 4.4):</u> Section 4.4 clarifies the Rule's provision that DG customers and community DG customers are responsible for all utility interconnection costs. However, the proposed Rule also retains the current Commission Rule's provision that utilities shall calculate interconnection costs in a non-discriminatory basis with respect to distribution level customers with similar load characteristics.

Entergy objected to the Commission's previous Rule's provision allowing for a customer or utility to request that interconnection costs be paid over a reasonable period of time rather than fully upfront. Staff agrees with the position that needlessly subjects a utility, and ultimately ratepayers, to party default risks. For this reason, Staff has removed this provision from the proposed Rule.

Large Distributed Generation Project (Section 4.5): Section 4.5 maintains the existing Commission allowance for distributed generation proposals that are greater than 300 kW upon a finding by the Commission that the project is in the public interest. Of concern to some parties was the existing Commission provision that allows for utilities to request approval of ratepayer recovery of Lost Revenues associated with large distributed generation proposals. Walmart specifically requested that this provision be deleted, in recognition of the fact that Commission-approved Formula Rate Plans would already compensate utilities for any Lost Revenues. Staff agrees with these positions and has thus removed the provision allowing for recovery from ratepayers of lost revenues associated with large distributed generation projects.

Renewable Energy Credits (Section 4.6): Section 4.6 establishes the treatment of Renewable Energy Credits ("RECs") for use within renewable energy or solar renewable energy markets. All parties to this proceeding disagreed with the current treatment of Renewable Energy Credits ("RECs") or solar RECs ("SRECs") in the Commission's Rule, including a rare agreement between a utility interest (Entergy) and environmental interests.

Louisiana has not established a Renewable Portfolio Standard ("RPS") or otherwise developed a Rule establishing the creation of RECs for use with meeting Commission policy goals. Therefore, the Commission's previous Rule was written to prevent the registration or sale of any REC for all Louisiana Distributed Generation Customers. Parties requested that the Commission clarify that the Commission only reserved the right to determine the eligibility and applicability of RECs as it applied to future Commission policymaking. To the extent a Distributed Generation Customer wished to register a generation system for use in renewable energy or solar renewable energy market not associated with Commission policymaking, the customer should be allowed to do so. Under such a structure, the Distributed Generation Customer would retain exclusive ownership rights of such RECs or SRECs until relinquished through sale.

Interconnection of Distributed Generation Facilities to Existing Electric Power Systems (Section 5): Section 5 lays out the proposed Rule's regulation of interconnection agreements. The majority of this section is

retained from the Commission's current Rule. However, subsection 5.2.4 modified existing Commission practice to reduce the time required for distributed generation customers seeking interconnection approval from a utility from 45 days, to 14 business days. The proposed Rule also adds additional clarification to Subsection 5.3, clarifying that DG customers are required to notify, in writing, the applicable electric utility before any system or interconnection modifications are made by the DG customers. This includes increases to the generating capacity of the DG system. Likewise, Subsection 5.4 clarifies that valid interconnection agreements are transferable on the sale of the property that contains the DG facility or community DG facility.

Pursuant to party comments, Staff has additionally clarified that the Standard Interconnection Agreement, attached to the Rule as Appendix A, is included as an illustrative example of such agreement meeting the Commission's standards. As was explained previously in this report, Entergy also requested that Staff revise this section to reduce the burden placed upon utilities to ensure continued compliance with these proposed Rule. Staff disagrees with this revision as it would relieve utilities of the burden of enforcing compliance with the proposed Rule, while not delegating this responsibility to anyone.

Distributed Generation Tariff (Section 6.1): Section 6.1 requires utilities to file an updated tariff with the Commission 30 days after the effective date of the proposed Rule. This is unchanged from existing Commission requirements.

Avoided Costs (Section 6.2): Section 6.2 of the proposed Rule establishes parameters associated with the cost-based rate applied to electricity generated and sold to electric utilities by DG facilities. Section 6.2 establishes two potential calculations of avoided costs. The first would rely upon Section 204(a)(c) and (e) of the Commission's General Order dated February 27, 1998, defining utility avoided cost of generation. In addition to complying with the Commission's prior precedent on avoided cost of generation, electric utilities must consider alternative avoided cost provisions including seasonally differentiated avoided cost rates, time-variant avoided cost rates, avoided costs determined by local marginal prices, and adjustments for avoided line losses. Based on

party comments, Staff has clarified the included language in Section 6.2 to clarify that utilities shall be allowed to consider results from organized energy markets in their proposed calculations of alternative avoided costs.

As an alternative to the above-mentioned calculation of avoided costs, electric utilities can propose innovative avoided cost rates subject to Commission approval. Calculations of such rates are purposefully not defined. However, it is expected that such rates may include allowances for the environmental benefits of renewable energy technologies and the benefits to electric distribution systems from avoided peak capacity needs.

Distributed Generation Charges (Section 6.3): Section 6.3 clarifies that the Commission may, in the future, authorize electric utilities to assess a greater fee or customer charge on Distributed Generation Customers following notice and opportunity for public comment. Consistent with the change noted earlier with respect to Section 4.5.4, references to the potential for approval of the recovery of lost revenues associated with the installation of Distributed Generation Facilities has been removed.

Restricted Service (Section 6.4): Section 6.4 retains the provision in the Commission's existing Rule that prohibits DG service associated with customers taking service under a temporary service schedule.

Facilities installed prior to Effective Date (Section 7.1): Section 7.1 exempts, or grandfathers, all systems installed prior to the Effective Date of the proposed Rule. These systems will be compensated pursuant to the existing net metering tariff effective for the customer as of the day immediately prior to the Effective Date of the proposed Rule. In designing Section 7.1, Staff recognized the inherent equity imbalance associated with allowing a segment of customers to continue to be compensated at greater levels compared to new customers seeking to construct DG systems. Therefore, Staff included provisions that attempt to reduce the number of exempted DG systems over time, including removing the grandfather provision entirely after five years pursuant to Subsection 7.1.4.

Subsection 7.1.2 outlines the situation in which a grandfathered customer significantly modifies the existing DG system such as increasing its generation capabilities. Under this circumstance, the customer would no longer be grandfathered, and all electrical generation from the DG facility would be compensated at the approved avoided cost rate. Likewise, Subsection 7.1.3. outlines the condition that a grandfathered customer transfers the DG facility to another owner. Under this circumstance, the customer would no longer be grandfathered, as the grandfathered status is applied to the customer, and not the DG facility.

Filling and Reporting Requirements (Section 7.2): Section 7.2 retains the Commission's existing requirements related to annual reports to be filed with the Commission by March 1st of each year.

Integrated Resource Plan (Section 7.3): Section 7.3 of the proposed Rule establishes requirements associated with the incorporation of DG in utility integrated resource plans. DG provides many resource benefits to utility systems. Section 7.3 is written with recognition of this fact, and further recognition that utility customers should not pay for additional utility upgrades that are not required due to the presence of DG resources. While the proposed Staff Rule does not define an explicit methodology for the incorporation of DG resources into future utility integrated resource plans, it is recognized that DG systems are not dispatchable in the manner of traditional resources, and that this effects the capacity benefits these resources provide for resource planning purposes.

Commission Review (Section 7.4): Section 7.4 retains the Commission's authority to revisit the proposed Rule, and its revisions, at any time.

Appendix A – Standard Interconnection Agreement: Appendix A provides an illustrative example of a potential Standard Interconnection Agreement complying with the Commission's standards. This example is unchanged from that attached to the Commission's existing Rule, with the exception of the removal of legacy

elements referring to generation fuel of the generator to be interconnected and the change in filing requirement reduced from 45 days to 14 business days.

Appendix B -- Accuracy Requirements for Service Watt-Hour Meters, Demand Meters, and Pulse Recorders: Appendix B lists the Commission's current accuracy requirements for Distributed Generation-related metering systems. It remains unchanged from the similar appendix attached to the Commission's existing Rule.

Appendix C – LPSC Net Metering Annual Report: Appendix C provides the framework for the Commission's existing requirements associated with utility Annual Reports to be filed by March 1st of each year. The contents of Appendix C, have not been changed from that attached to the Commission's current Rule.

<u>ATTACHMENT: EXHIBIT 1</u>

Proposed Distributed Generation Rule

RULE FOR DISTRIBUTION-LEVEL CUSTOMER ENERGY GENERATION

Section I: Purpose and Definitions.

1.1. **Purpose:** The purpose of this Rule is to define the terms and conditions under which electric and/or combined electric and gas utilities will provide service to behind-the-meter, distribution-level generation.

1.1.1. Utilities will be required to provide fair, open and non-discriminatory access to all forms of distributed generation that are eligible and in compliance with this Rule.

1.1.2. Utilities will facilitate the safe interconnection of qualifying customer-owned distributed generation.

1.1.3. Distributed generation of all types will be reimbursed for any on-site generation electricity that is put to the distribution grid at rates that are cost-based as provided by Section 1.2.1 and 6.2.

1.1.4. All distributed generation-related costs will be recovered through distributed generation-related rate riders. The costs of distributed generation will not be subsidized by, nor socialized across, other customer classes.

1.1.5. Utilities will be responsible for monitoring existing distributed generation installations.

1.1.6. Utilities will be expected to account for distributed generation resources in their future resource planning processes.

1.2. **Definitions:** For the purposes of this Rule, the following terms will have the following meanings:

1.2.1. Avoided Costs: The incremental cost to an electric utility for energy or capacity or both which, but for the purchase from the distributed generation facility, the utility would generate itself or purchase from the market and will be calculated based upon the definitions included in this Rule (Section 6.2).

1.2.2. Billing Period: The billing period for a distributed generation facility will be the same as the billing period under the Distributed Generation Customer's applicable standard rate rider.

1.2.3. Commission: The Louisiana Public Service Commission.

1.2.4. Commercial Customer: A customer served under a utility's standard rate schedule applicable to commercial service.

1.2.5. Community Distributed Generation Facility: A facility for the production of electric energy that:

1.2.5.1. Has a generating capacity of not more than three hundred (300) kilowatts; and,

1.2.5.2. Is owned, as defined by LA Civil Code Article 477, by a community distributed generation organization; and,

1.2.5.3. Is located in the same electric service territory as all member Distributed Generation Customers; and,

1.2.5.4. Can operate in parallel with an electric utility's existing transmission and distribution facilities; and,

1.2.5.5. Is a separate facility with its own electric meter from any of the Distributed Generation Customers comprising the members of the community distributed generation organization; and,

1.2.5.6. Operates exclusively to offset part or all of the member Distributed Generation Customers' requirements for electricity.

1.2.6. Community Distributed Generation Organization: An organization of member Distributed Generation Customers that owns, as defined by LA Civil Code Article 477, and operates a community distributed generation facility.

1.2.7. Distributed Generation Customers: Any customer who chooses to take electric service under a distributed generation rate rider, as set out below. For commercial customers, this includes subsidiaries and affiliates.

1.2.8. Distributed Generation Facility: A facility for the production of electrical energy that:

1.2.8.1. Has a generating capacity of not more than twenty-five (25) kilowatts for residential or three hundred (300) kilowatts for commercial or agricultural use.

1.2.8.2. Can operate in parallel with an electric utility's existing transmission and distribution facilities.

1.2.8.3. Is intended primarily to offset part or all of the Distributed Generation Customer's requirements for electricity as outlined in Section 4.3.

1.2.8.4. Is designated by the Commission as eligible for distributed generation service pursuant to Section 4.5.

1.2.9. Electric Utility/Utility: An investor-owned electric utility, an electric cooperative, or any other entity meeting the definition of a "public utility" as used in La R.S. 45:1161.

1.2.10. Effective Date: The effective date of the Commission's General Order in Docket No. R-33929.

1.2.11. Interconnection Costs: The reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a distributed generation facility, to the extent the costs are in excess of the corresponding costs which the electric utility would have incurred had it not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

1.2.12. Parallel Operation: The operation of on-site generation by a Distributed Generation Customer while the Distributed Generation Customer is connected to the utility's distribution system.

1.2.13. Renewable Energy Credit: The environmental, economic, and social attributes of a unit of electricity, such as a megawatt hour, generated from renewable fuels that can be sold or traded separately.

1.2.14. Residential Customer: A customer served under a utility's standard residential rate schedules.

Section II: Scope.

2.1. <u>Applicability:</u>

2.1.1. This Rule apply to the regulation of distributed generation service for jurisdictional Electric Utilities.

2.1.2. Distributed Generation Customers taking service under the provisions of a Utility's distributed generation rate rider may not simultaneously take service under the provisions of any other alternative source generation or cogeneration rate schedule or rider except as provided herein.

2.2. <u>General Condition:</u> The Distribution-Level Customer Energy Generation Rule is not intended to, and do not affect or replace any Commission approved general service regulation, policy, procedure, rule or service application of any utility which address items other than those covered in this Rule.

Section III: Distributed Generation Requirements.

3.1. <u>Electric Utility Requirements:</u>

3.1.1. A jurisdictional Electric Utility that offers residential or commercial electrical service, or both, shall allow Distributed Generation Facilities or

Community Distributed Generation Facilities to be interconnected using a standard meter capable of registering the flow of electricity in two (2) directions. A two-channel meter or other type meter which is capable of determining the net energy from the Distributed Generation Facility can be utilized.

3.1.2. If the meter that is currently installed on the Distributed Generation Facility is incapable of registering the flow of electricity in two directions, an appropriate meter or meters to measure the flow of electricity in each direction shall be installed by the Electric Utility.

3.1.3. If an additional meter or meters are installed, the Distributed Generation Facility's metering calculation shall yield the same result as when a single meter is used.

3.2. <u>Metering Requirements:</u>

3.2.1. Metering equipment shall be installed to both accurately measure the electricity supplied by the Electric Utility to each Distributed Generation Customer or Community Distributed Generation Organization and also to accurately measure the electricity generated by each Distributed Generation Customer or Community Distributed Generation Organization that is fed back to the Electric Utility over the applicable Billing Period.

3.2.2. Accuracy requirements for a meter operating in both forward and reverse registration modes shall be defined in Appendix B.

3.3. <u>Faulty meter operations or billing:</u>

3.3.1. To the extent a faulty meter or other billing error has resulted in a Distributed Generation Customer or Community Distributed Generation Organization receiving insufficient credits or payments, the Utility shall make the appropriate credits or payments in the next Billing Period.

3.3.2. To the extent a faulty meter or other billing error has resulted in the Distributed Generation Customer or Community Distributed Generation Organization receiving excess credits or payments, then the Utility shall reduce future credits or payments by the excess amount in the next available Billing Period.

3.3.3. Nothing in this section is intended to supersede the provisions of the Commission's General Order dated April 21, 1993, regarding computer glitches and billing errors.

3.4. <u>Meters and meter installation charges:</u>

3.4.1. Except as set forth in 3.4.2 and 3.4.3 below, the cost of replaced metering equipment to allow for distributed generation pursuant to 3.1.2 shall be the

responsibility of the Electric Utility and shall not be assessed on the Distributed Generation Customer.

3.4.2. The Electric Utility may assess a one-time charge to recover costs associated with new additional metering equipment, if an additional meter or meters is requested by the Distributed Generation Customer.

3.4.3. The Electric Utility may assess a one-time charge to the Distributed Generation Customer to cover the incremental costs of meter installation. This charge shall be clearly identified in the Utility's Rate Rider and shall be cost-based. To the extent such a rider is not already on file with the Commission, any new filings will be subject to the Commission's rules as established in the upcoming rulemaking docket R-37438.

Section IV: Distributed Generation Operations.

4.1. Billing for distributed generation facilities:

4.1.1. On a monthly basis, the Distributed Generation Customer shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules for the energy delivered by the Utility.

4.1.2. Electricity generated and fed to the Electric Utility by the Distributed Generation Facility shall be credited against the Distributed Generation Customer standard volumetric rate schedule charge during the current Billing Period. Electricity generated and fed to the Electric Utility by the Distributed Generation Facility shall be valued by the Electric Utility, for bill crediting purposes, as the product of the kWh exported to the Electric Utility and the Utility's applicable Avoided Cost rate (as defined in Section 6.2).

4.1.2.1. The Electric Utility's applicable Avoided Cost rate shall be clearly identified on the Distributed Generation Customer's monthly bill.

4.1.2.2. Section 4.1.2. shall not apply in instances where conditions identified in Section 7.1 ("Facilities installed prior to the Effective Date") are applicable.

4.1.3. At the end of the Billing Period, if the value of the electricity generated by the Distributed Generation Facility exceeds the cost of the electricity supplied by the Electric Utility to the Distributed Generation Customer, subject to the applicable rate schedule, the Distributed Generation Customer's monthly bill shall be credited, on the next Billing Period, for the monetary value of the excess distributed generation as defined in Section 4.1.2.

4.1.3.1. If the Distributed Generation Customer has multiple service accounts with the Electric Utility, the Distributed Generation

Customer may elect, after notifying the Electric Utility and subject to Commission review if disputed by the Electric Utility, to apply credits pursuant to Section 4.1.3. to any other eligible metered account.

4.1.3.2. For the final month in which the Distributed Generation Customer takes service from the Electric Utility, the Electric Utility shall issue a check within sixty (60) days to the Distributed Generation Customer for the balance of any credit due in excess of the amounts owed by the Distributed Generation Customer to the Electric Utility.

4.1.3.3. Section 4.1.3. shall not apply in instances where the conditions identified in Section 7.1 are applicable.

4.2. <u>Billing for Community Distributed Generation Facilities:</u>

4.2.1. On a monthly basis, the Electric Utility shall determine the total electrical energy generated by the Community Distributed Generation Facility and fed back to the Electric Utility expressed in kWh.

4.2.2. The value of the electrical energy fed to the Electric Utility by the Community Distributed Generation Facility shall be determined as the product of the Community Distributed Generation Facility's generation expressed in kWh and the Utility's Avoided Cost rate.

4.2.3. For each Distributed Generation Customer, who is a member of a Community Distributed Generation Organization, the Electric Utility's Avoided Cost rate shall be clearly identified on that customer's monthly bill.

4.2.4. Credit calculated pursuant to Section 4.2.2. shall be credited to each Community Distributed Generation Organization member's next bill for electric service.

4.2.5. Allocation of bill credits shall be determined by the Community Distributed Generation Organization, and subject to approval by the Commission.

4.3. <u>Sizing of distributed generation facilities:</u>

4.3.1. Distributed Generation Facilities that begin operation, or are modified and continue operations after the Effective Date, shall be designed to produce no more than 100 percent of the Distributed Generation Customer's expected aggregate electric consumption, calculated as the average of the two previous 12 month periods of actual electric usage at the time of installation of the Distributed Generation Facility.

4.3.2. If two previous 12-month periods of actual electric usage are not available, electric consumption will be estimated based on the usage of other similarly-situated customers.

4.4. Additional charges for distributed generation facilities:

4.4.1. All Distributed Generation Customers and Community Distributed Generation Organizations shall be required to reimburse the Electric Utility for all Interconnection Costs.

4.4.2. Electric Utility shall calculate Interconnection Costs for each request on a nondiscriminatory basis with respect to distribution level customers with similar load characteristics.

4.5. Large distributed generation projects:

4.5.1. The Commission may allow distributed generation projects greater than 300kW for a Commercial Distributed Generation Customer, if the customer's project is found to be in the public interest.

4.5.1.1. All large distributed generation project interconnection requests shall be docketed and published in the Commission's official bulletin prior to Commission approval.

4.5.1.2. Expedited treatment may be allowed by the Commission upon a showing of good cause by the applicant.

4.5.2. Large Distributed Generation Customers shall reimburse the Electric Utility for the costs of all reasonable and necessary engineering analyses and/or studies performed by the Electric Utility to facilitate the project's interconnection and grid operation.

4.5.3. Large Distributed Generation Customers shall compensate the Electric Utility for necessary modifications to the Electric Utility's system necessary to interconnect the large distributed generation project.

4.5.4. The Commission reserves its rights to determine, on an individual application basis, the appropriate bill credit granted to large distributed generation projects for the electricity put to the Utility distribution grid and whether or not any modifications to the terms and conditions for distributed generation reimbursements defined in Section 4.5 of this Rule apply.

4.5.5. All large distributed generation projects are bound by all existing rules and procedures regarding interconnection.

4.6. Renewable energy credits ("RECs"):

4.6.1. The Commission has the sole right to determine the eligibility and applicability of RECs associated with all types of distribution level interconnected renewable distributed generation as it applies to Commission policymaking. As necessary, the Commission will develop rules for the creation, trade, monitoring and verification of RECs or solar

RECs ("SRECs") for application to Commission policymaking at such time that it is in the public interest to develop such rules.

4.6.2. To the extent not restricted by future Commission policymaking, the Distributed Generation Customer or Community Distributed Generation Organization shall retain ownership of all RECs or SRECs associated with electric energy produced from the Distributed Generation Facility or Community Distributed Generation Facility, unless the Distributed Generation Customer or Community Distributed Generation Organization has relinquished such ownership by contractual agreement with a third party.

Section V: Interconnection of Distributed Generation Facilities to Existing Electric Power Systems.

5.1. <u>Standard Interconnection Agreement:</u>

5.1.1. Each Electric Utility shall file, for approval by the Commission, a Standard Interconnection Agreement for Distributed Generation Facilities (please see Appendix A as an illustrative example of a Standard Interconnection Agreement for Distributed Generation Facilities). If an Electric Utility has a standard Interconnection Agreement, it may use its own Agreement.

5.1.2. An Electric Utility may request a modification to its Standard Interconnection Agreement but no proposed changes or modifications will be allowed without prior Commission approval.

5.1.3. The Standard Interconnection Agreement shall describe any and all Interconnection Costs, and other customer charges for which the Distributed Generation Customer or Community Distributed Generation Organization shall be responsible.

5.1.4. The Standard Interconnection Agreement shall include provisions that explicitly allow the Utility to periodically inspect Distributed Generation and Community Distributed Generation Facilities. Utilities will be responsible for auditing Distributed Generation and Community Distributed Generation Facility installations to ensure their continued compliance with the Standard Interconnection Agreement and that any system modifications that have been made after the original interconnect have been reported to the Utility and are in compliance with this Rule.

5.1.5. Utilities will be responsible for ensuring that Distributed Generation and Community Distributed Generation Facilities are in compliance with the original or modified terms of their Standard Interconnection Agreement. Utilities shall recover the costs of ensuring this compliance from customers

taking service under their respective Distributed Generation or Community Distributed Generation tariffs and not from other ratepayer classes.

5.2. Requirements for Initial Interconnection of Distributed Generation Facilities:

5.2.1. A Distributed Generation Customer or Community Distributed Generation Organization shall execute a Standard Interconnection Agreement for Distributed Generation Facilities (see Appendix A as an illustrative example of a Standard Interconnection Agreement for Distributed Generation Facilities) prior to interconnection with the Utility's distribution facilities. The Standard Interconnection Agreement shall set forth the expenses for which the Distributed Generation Customer or Community Distributed Generation Organization shall be responsible.

5.2.2. A Distributed Generation Facility or Community Distributed Generation Facility shall be capable of safe parallel operations prior to commencing the delivery of power into the Utility system at a single point of interconnection.

5.2.3. Interconnected facilities shall have a visibly open, lockable, manual disconnection switch that is accessible by the Electric Utility and clearly labeled, unless this requirement is waived by the Electric Utility pursuant to Section 4 of the Standard Interconnection Agreement.

5.2.4. The Distributed Generation Customer or Community Distributed Generation Organization shall submit a Standard Interconnection Agreement to the Electric Utility at least fourteen (14) business days prior to the date the customer intends to interconnect the Distributed Generation Facility or Community Distributed Generation Facility to the Utility's facilities.

5.2.4.1. The Distributed Generation Customer or Community Distributed Generation Organization will be required to provide documentation indicating the date upon which the notification was physically or electronically provided to the Electric Utility.

5.2.4.2. Part I, Standard information, Sections 1 through 4 of the Standard Interconnection Agreement, or applicable information contained within approved Standard Interconnection Agreements, must be completed for the notification to be valid.

5.2.4.3. The Distributed Generation Customer or Community Distributed Generation Organization shall have all equipment necessary to complete the interconnection prior to such notification.

5.2.4.4. If mailed, the date of notification shall be the third day following the mailing of the Standard Interconnection Agreement.

5.2.4.5. The Electric Utility shall provide a copy of the Standard Interconnection Agreement upon request.

5.2.5. The Distributed Generation Facility or Community Distributed Generation Facility shall, at the Distributed Generation Customer or Community Distributed Generation Organization expense, meet all safety and performance standards established by local and national electric codes including the National Electric Code ("NEC"), the Institute of Electrical and Electronics Engineers ("IEEE"), the National Electrical Safety Code ("NESC"), and Underwriters Laboratories ("UL").

5.2.6. The Distributed Generation Facility or Community Distributed Generation Facility shall, at the Distributed Generation Customer or Community Distributed Generation Organization expense, meet all reasonable safety and performance standards adopted by the Utility, and approved by the Commission, to assure safe and reliable operation of the facility and the Utility's distribution grid.

5.2.7. If the Electric Utility's existing facilities are not adequate to interconnect with the Distributed Generation Facility or Community Distributed Generation Facility, any changes will be performed in accordance with the Electric Utility's Standard Interconnection Agreement for Distributed Generation Facilities as well as separate policies regarding extension of facilities.

5.3. **<u>Modifications or changes to a distributed generation facility:</u>**

5.3.1. All Distributed Generation Facilities and Community Distributed Generation Facilities will be required to provide Utility access to their systems, on a periodic basis, to assure compliance with the terms and representations of the characteristics of their systems in their original interconnection applications.

5.3.2. All Distributed Generation Facilities and Community Distributed Generation Facilities shall be required to notify the Electric Utility, in writing, of any material system or interconnection modifications to their systems that include, but are not limited to increases in the generation capacities of these systems.

5.3.3. Distributed Generation and Community Distributed Generation Facilities will allow Utilities to inspect all modifications to their systems for continued compliance with the safety provisions in Section 4.3.

5.3.4. Utilities that find material modifications or changes made to a Distributed Generation Facility or Community Distributed Generation Facility that would render the facility in violation of the safety provisions of Section 4.3. shall report such violations to the Commission for further action.

5.3.5. After notice, the Commission may require Utilities to disconnect Distributed Generation Facilities and Community Distributed Generation Facilities that are found to be out of compliance with this Rule. To the extent that it is impractical to provide notice due to emergency conditions or threat to grid reliability, the Commission may allow an immediate disconnection. Nothing herein should be interpreted to alter the rights of the Utilities or customers provided in the Utilities' Terms of Service.

5.4. **Transferability:** Valid interconnection agreements shall be transferable to the purchaser of the property on which the facility is located upon transfer or activation of electric service provided that such Distributed Generation or Community Distributed Generation Facilities are in compliance with this Rule at the time of the transfer.

Section VI: Distributed Generation Rate Rider.

6.1. **Distributed generation Rate Rider:** Each Electric Utility shall update its tariff on file with the Commission within 30 days from the effective date of these Rules to provide a Rate Rider in accordance with these Rules. The distributed generation Rate Rider shall be filed with and maintained by the Commission.

6.2. **Avoided Costs:** Distributed generation Rate Riders shall include an Avoided Cost rate for the crediting of any electricity from Distributed Generation Facilities and Community Distributed Generation Facilities with a design capacity of 300kW or less. Avoided Cost rates must either:

6.2.1. Comply with Section 204(a)(c) and (e), regarding standard rates for purchases at avoided costs, of the Commission's General Order dated February 27, 1998, provided the Electric Utility considers the following avoided cost provisions:

6.2.1.1. Items including, but not limited to, seasonally differentiated avoided cost rates, time-variant avoided cost rates, avoided generation capacity costs, avoided transmission and distribution costs, avoided costs determined by locational marginal prices and/or other market-based metrics from organized markets that include values (credits) for renewables and other environmental/clean air markets.

6.2.1.2. Adjustments for avoided line losses.

6.2.1.3. All avoided cost provisions must be supported by evidence and approved by the Commission prior to implementation.

6.2.1.4. Unless otherwise specified in the order approving the rate, if the Commission allows such adjustment to reflect criteria described above, the rate shall be updated bi-annually and all

amounts credited to customers for net metered energy exported to the electric utility shall be eligible for recovery pursuant to the LPSC's General Order No. U-21497, which governs the types of costs that may be recovered through a utility's monthly Fuel Adjustment Clause; or

6.2.2. Electric Utilities may propose innovative avoided cost rates for distributed generation purposes. Innovative avoided cost rates shall be supported by evidence and approved by the Commission prior to implementation.

6.3. **Distributed generation charges:**

6.3.1. Following notice and opportunity for public comment within the context of a general rate case or a formula rate plan request, the Commission may authorize an Electric Utility to assess a greater fee or customer charge, of any type, to Distributed Generation Customers.

6.3.2. Requests for additional charges for Distributed Generation Customers shall be accompanied by supporting evidence, including, but not necessarily limited to, cost/benefit analyses and studies.

6.4. **Restricted service:** Distributed generation Rate Riders shall not be made available to customers taking temporary service.

Section VII: Other Provisions.

7.1. **Facilities installed prior to the Effective Date:**

7.1.1. For Distributed Generation Facilities, except large distributed generation projects pursuant to Section 4.5., certified by the Electric Utility as interconnected to the electric grid prior to the Effective Date, the Distributed Generation Customer associated with the facility shall be compensated pursuant to existing tariff effective on the calendar day immediately prior to the Effective Date.

7.1.2. If the Distributed Generation Facility makes a material change or modification to a Distributed Generation Facility installed prior to the Effective Date, which modification includes but is not limited to an increase in the generation capacity of the Distributed Generation Facility, the Distributed Generation Facility shall be credited consistent with Section 4.1.

7.1.3. If the Distributed Generation Facility is transferred to another owner other than the owner on the calendar day immediately prior to the Effective Date, the Distributed Generation Facility shall be credited consistent with Section 4.1.

7.1.4. Section 7.1. shall no longer apply to any Distributed Generation Facility five years after the Effective Date.

7.2. **Filing and reporting requirements:** Each Electric Utility shall file a distributed generation annual report no later than March 1 of each year, covering the prior calendar year.

7.2.1. Distributed generation annual reports shall be in Excel format, and consistent with the form provided in Appendix C.

7.3. **Integrated resource plan:** Electric Utilities that file an Integrated Resource Plan or comparable electric system planning with the Commission shall include an analysis of distributed generation subject to this Rule as part of the Electric Utility's Integrated Resource Plan or comparable electric system planning document. Such analysis shall include:

7.3.1. Documentation on the current level of distributed generation (in capacity and installation terms) within the Electric Utility's service territory as well as for the prior five calendar years.

7.3.2. A discussion and analysis of the impact that distributed generation installations are having on the Electric Utility's system resource requirements.

7.3.3. A forecast of future distributed generation (in terms of installations and capacity) for at least a five year period.

7.3.4. Electric Utilities are encouraged to provide as part of its IRP or comparable analysis, documentation on the monetary value of the avoided energy and capacity requirements distributed generation has provided to the Utility's system historically, and forecasts of the expected monetary benefits associated with avoided energy and capacity requirements due to distributed generation.

Commission Review: The Commission may revisit this Rule at any time.

APPENDIX A
STANDARD INTERCONNECTION AGREEMENT FOR DISTRIBUTED GENERATION FACILITIES

I. STANDARD INFORMATION

Section 1. Customer Information

Name:____

Mailing Address:____

City:____________________ State:___________________ Zip Code:_____________________

Facility Location (if different from above):_________________________________

Daytime Phone: Evening Phone:____

Utility Customer Account (from electric bill):__________________________________

Section 2. Generation Facility Information

Generator Rating (**kW**): AC or DC (circle one)
Describe Location of Accessible and Lockable Disconnect:_______________________________

Inverter Manufacturer: Inverter Model:____

Inverter Location: Inverter Power Rating:____

Section 3. Installation Information

Attach a detailed electrical diagram of the distributed generation facility.
Installed by:___________________________Qualifications/Credentials :_____________________

Mailing Address:____

City:____________________ State:___________________ Zip Code:_____________________

Daytime Phone:_______________________Installation Date:_____________________________

Section 4. Certification

1. The system has been installed in compliance with the local Building/Electrical Code of (City/Parish)

____

Signed (Inspector):_________________________________Date:__________________

(In lieu of signature of inspector, a copy of the final inspection certificate may be attached.)

2. The system has been installed to my satisfaction and I have been given system warranty information
and an operation manual, and have been instructed in the operation of the system.
Signed (Owner):___________________________________Date:__________________

Section 5. Utility Verification and Approval

1. Facility Interconnection Approved:________________ Date:_____________________

Metering Facility Verification by:__________________Verification Date:____________

2. INTERCONNECTION AGREEMENT TERMS AND CONDITIONS

This Interconnection Agreement for Distributed Generation Facilities ("Agreement") is made and entered into this _____ day of ____________, 20__, by ______________________("Utility") and _______________("Customer"), a ________________ (specify whether corporation or other), each hereinafter sometimes referred to individually as "Party" or collectively as the "Parties". In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Section 1. The Distributed Generation Facility

The Distributed Generation Facility meets the requirements of "Distributed Generation Facility", as defined in the Louisiana Rule for distribution-level customer energy generation ("Distributed Generation Rules").

Section 2. Governing Provisions

The terms of this agreement shall be interpreted under and subject to Louisiana Law. The parties shall be subject to the provisions of Act No. 653 of the 2003 Regular Session, the terms and conditions as set forth in this Agreement, the Distributed Generation Rules, and the Utility's applicable tariffs.

Section 3. Interruption or Reduction of Deliveries

The Utility shall not be obligated to accept and may require Customer to interrupt or reduce deliveries when necessary in order to construct, install, repair, replace, remove, investigate, or inspect any of its equipment or part of its system; or if it reasonably determines that curtailment, interruption, or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with prudent electrical practices. Whenever possible, the Utility shall give the Customer reasonable notice of the possibility that interruption or reduction of deliveries may be required. Notwithstanding any other provision of this Agreement, if at any time the Utility reasonably determines that either the facility may endanger the Utility's personnel or other persons or property, or the continued operation of the Customer's facility may endanger the integrity or safety of the Utility's electric system, the Utility shall have the right to disconnect and lock out the Customer's facility from the Utility's electric system. The Customer's facility shall remain disconnected until such time as the Utility is reasonably satisfied that the conditions referenced in this Section have been corrected.

Section 4. Interconnection

Customer shall deliver the as-available energy to the Utility at the Utility's meter.

Utility shall furnish and install a standard kilowatt-hour meter. Customer shall provide and install a meter socket for the Utility's meter and any related interconnection equipment per the Utility's technical requirements, including safety and performance standards. Customer shall be responsible for all costs associated with installation of the standard kilowatt-hour meter and testing in conformity with Section 3.2. of the Distributed Generation Rules.

The customer shall submit a Standard Interconnection Agreement to the electric utility at least fourteen (14) business days prior to the date the customer intends to interconnect the distributed generation facilities to the utility's facilities. Part I, Standard Information Sections 1 through 4 of the Standard Interconnection Agreement must be completed for the notification to be valid. The customer shall have all equipment necessary to complete the interconnection prior to such notification. If mailed, the date of notification shall be the third day following the mailing of the Standard Interconnection agreement. The net metering customer shall be required to provide documentation indicating the date upon which the notification was mailed to the electric utility. The electric utility shall provide a copy of the Standard Interconnection Agreement to the customer upon request.

Following notification by the customer, the utility shall review the plans of the facility and provide the results of its review to the customer within fourteen (14) business days. Any items that would prevent parallel operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

To prevent a distributed generation customer from back-feeding a de-energized line, the customer shall install a manual disconnect switch with lockout capability that is accessible to utility personnel at all hours. This requirement for a manual disconnect switch may be waived if the

following three conditions are met: 1) The inverter equipment must be designed to shut down or disconnect and cannot be manually overridden by the customer upon loss of utility service; 2) The inverter must be warranted by the manufacturer to shut down or disconnect upon loss of utility service; and 3) The inverter must be properly installed and operated, and inspected and/or tested by utility personnel. The decision to grant the waiver will be at the Utility's discretion, however, any decision will be subject to review by the Commission.

Customer, at his own expense, shall meet all safety and performance standards established by local and national electrical codes including the National Electrical Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), the National Electrical Safety Code (NESC), and Underwriters Laboratories (UL).

Customer, at his own expense, shall meet all safety and performance standards adopted by the utility and filed with and approved by the Commission pursuant to Section 5.2.6. of the Distributed Generation Rules that are necessary to assure safe and reliable operation of the net metering facility to the utility's system.

Customer shall not commence parallel operation of the distributed generation facility until the distributed generation facility has been inspected and approved by the Utility. Such approval shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, the Utility's approval to operate the Customer's distributed generation facility in parallel with the Utility's electrical system should not be construed as an endorsement, confirmation, warranty, guarantee, or representation concerning the safety, operating characteristics, durability, or reliability of the Customer's net metering facility.

Proposed modifications or changes to a distributed generation facility shall be evaluated by the Utility prior to being made. The Customer shall provide detailed information describing the modifications or changes to the Utility in writing prior to making the modifications to the distributed generation facility. The Utility shall review the proposed changes to the facility and provide the results of its evaluation to the Customer within fourteen (14) business days of receipt of the Customer's proposal. Any items that would prevent parallel operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

Section 5. Maintenance and Permits

The customer shall obtain any governmental authorizations and permits required for the construction and operation of the net metering facility and interconnection facilities. The Customer shall maintain the distributed generation facility and interconnection facilities in a safe and reliable manner and in conformance with all applicable laws and regulations.

Section 6. Access to Premises

The Utility may enter the Customer's premises to inspect the Customer's protective devices and read or test the meter. The Utility may disconnect the interconnection facilities without notice if the Utility reasonably believes a hazardous condition exists and such immediate action is necessary

to protect persons, or the Utility's facilities, or property of others from damage or interference caused by the Customer's facilities, or lack of properly operating protective devices.

Section 7. Indemnity and Liability

Each party shall indemnify the other party, its directors, officers, agents, and employees against all loss, damages expense and liability to third persons for injury to or death of persons or injury to property caused by the indemnifying party's engineering design, construction ownership or operations of, or the making of replacements, additions or betterment to, or by failure of, any of such party's works or facilities used in connection with this Agreement by reason of omission or negligence, whether active or passive. The indemnifying party shall, on the other party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying party shall pay all costs that may be incurred by the other party in enforcing this indemnity. It is the intent of the parties hereto that, where negligence is determined to be contributory, principles of comparative negligence will be followed and each party shall bear the proportionate cost of any loss, damage, expense and liability attributable to that party's negligence.

Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to or any liability to any person not a party to this Agreement. Neither the Utility, its officers, agents or employees shall be liable for any claims, demands, costs, losses, causes of action, or any other liability of any nature or kind, arising out of the engineering, design construction, ownership, maintenance or operation of, or making replacements, additions or betterment to, the Customer's facilities by the Customer or any other person or entity.

Section 8. Notices

All written notices shall be directed as follows:

Attention:
[Utility Agent or Representative]

[Utility Name and Address]

Attention:
[Customer]
Name:__________________
Address:__________________
City:__________________

Customer notices to Utility shall refer to the Customer's electric service account number set forth in Section 1 of this Agreement.

Section 9. Term of Agreement

The term of this Agreement shall be the same as the term of the otherwise applicable standard rate schedule. This Agreement shall remain in effect until modified or terminated in accordance with its terms or applicable regulations or laws.

Section 10. Assignment

This Agreement and all provisions hereof shall inure to and be binding upon the respective parties hereto, their personal representatives, heirs, successors, and assigns. The Customer shall not assign this Agreement or any part hereof without the prior written consent of the Utility, and such unauthorized assignment may result in termination of this Agreement.

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed by their duly authorized representatives.

Dated this _________ day of ____________, 20__.

Customer:	Utility:
______________________________	______________________________
By:__________________________	By:__________________________
Title:_________________________	Title:_________________________
Mailing Address:	Mailing Address:
______________________________	________________________
______________________________	________________________

APPENDIX B
Accuracy Requirements for Service Watt-Hour Meters, Demand Meters, and Pulse Recorders:

A. Initial and Test Adjustments:

(1) No watt-hour meter that has an incorrect register constant, test constant, gear ratio or dial train, or that registers upon no load ("creeps"), shall be placed in service or allowed to remain in service without adjustment and correction. An in-service meter "creeps" when, with potential applied to all stators and with all load wires disconnected, the moving element makes one complete rotation in 10 minutes or less.

(2) No watt-hour meter that has an error in registration of more than the limits allowed in Rule 7.05.B. (1) shall be placed in service or be allowed to remain in service without adjustment. When meter error is found to exceed any one of the test limits in Rule 7.05.B.(1), it must be adjusted and a correction made to the customer's bill.

(3) Meters must be adjusted as closely as practicable to the condition of zero error by no greater than +/- 0.5 percent.

B. Acceptable Performance:

(1) Watt-Hour Meter Accuracy

The average error of the watt-hour meter shall not exceed +/- 2 percent.

	Test Current	Power Factor	Accuracy
Heavy Load	100% Test Amperes	1.0	+/- 2%
	100% Test Amperes	0.5	+/- 2%
Light Load	10% Test Amperes	1.0	+/- 2%

(2) Demand Meter Accuracy

The error of the demand register shall not exceed +/- 4% of the full scale value when tested between 25 percent and 100 percent of full scale value.

(3) Pulse Recorders

Pulse recorders shall not differ by more than +/- 2 percent from the corresponding kilowatt hour meter registration. The timing error shall not exceed +/- 2 minutes per day.

(4) Time of Use Meters

The timing element of time of use meters shall not be in error with central standard/daylight savings time by more than +/- 15 minutes.

C. Average Error:

(1) The average error of a service watt-hour meter shall be determined as follows:

$$WA = LL + 4HL / 5$$

Where:	WA	=	weighted average error of a service watt-hour meter
	LL	=	error at light load for 100 percent power factor
	HL	=	error at heavy load for 100 percent power factor

(2) The average error of the watt-hour portion of a demand meter shall be determined as follows:

$$WA = LL + 4HL + 2HHL / 7$$

Where:	WA	=	weighted average of error of the watt-hour portion of a demand meter.
	LL	=	error at light load of 100 percent power factor
	HL	=	error at heavy load for 100 percent power factor
	HHL	=	error at heavy load with 50 percent lagging power factor.

Appendix C-LPSC Net Metering Annual Report

Utility Name: ______________________

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Residential													
1 Number of Solar Unit Installations													
2 Solar Generation Capacity, kW (DC)													
3 Solar Inverter Capacity, kW (AC)													
4 Number of Wind Unit Installations													
5 Wind Generation Capacity, kW (DC)													
6 Wind Inverter Capacity, kW (AC)													
7 Number of Biomass Unit Installations													
8 Biomass Generation Capacity, kW (DC)													
9 Biomass Inverter Capacity, kW (AC)													
10 Number of Other Unit Installations (Microturbine, Fuel Cell)													
11 Other Generation Capacity, kW (DC)													
12 Other Inverter Capacity, kW (AC)													
13 Total Number of Installations													
14 Total Generation Capacity, kW (DC)													
15 Total Inverter Capacity, kW (AC)													
Commercial													
16 Number of Solar Unit Installations													
17 Solar Generation Capacity, kW (DC)													
18 Solar Inverter Capacity, kW (AC)													
19 Number of Wind Unit Installations													
20 Wind Generation Capacity, kW (DC)													
21 Wind Inverter Capacity, kW (AC)													
22 Number of Biomass Unit Installations													
23 Biomass Generation Capacity, kW (DC)													
24 Biomass Inverter Capacity, kW (AC)													
25 Number of Other Unit Installations (Microturbine, Fuel Cell)													
26 Other Generation Capacity, kW (DC)													
27 Other Inverter Capacity, kW (AC)													
28 Total Number of Installations													
29 Total Generation Capacity, kW (DC)													
30 Total Inverter Capacity, kW (AC)													
Total													
31 Number of Solar Unit Installations													
32 Solar Generation Capacity, kW (DC)													
33 Solar Inverter Capacity, kW (AC)													
34 Number of Wind Unit Installations													
35 Wind Generation Capacity, kW (DC)													
36 Wind Inverter Capacity, kW (AC)													
37 Number of Biomass Unit Installations													
38 Biomass Generation Capacity, kW (DC)													
39 Biomass Inverter Capacity, kW (AC)													
40 Number of Other Unit Installations (Microturbine, Fuel Cell)													
41 Other Generation Capacity, kW (DC)													
42 Other Inverter Capacity, kW (AC)													
43 Total Number of Installations													
44 Total Generation Capacity, kW (DC)													
45 Total Inverter Capacity, kW (AC)													

Utility Name: ______________________

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Utility													
46 Utility Peak Load (MW)													
47 Retail Portion													
48 Percent of System Peak ((line 44/1,000)/line 47)													
49 Energy Purchased from Net Metered Customers (kWh)													
50 Average Rate Paid for Energy Purchased from Net Metered Customers ($/kWh)													
51 Cost of Energy Purchased from Net Metered Customers ($)													
52 Utility Avoided Cost Rate ($/kWh)													
53 Utility Fuel Clause Rate ($/kWh)													

Service List for R-33929
as of 1/8/2019

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Foster L. Campbell, Commissioner

Lambert C Boissiere III., Commissioner

Mike Francis, Commissioner

Craig Greene, Commissioner

LPSC Staff Counsel

Kathryn Bowman, LPSC Staff Attorney

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Sierra Club Environmental Law Program

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